OGCB REPORT 69-G

IN THE MATTER OF AN APPLICATION OF CONSOLIDATED NATURAL GAS LIMITED UNDER THE GAS RESOURCES PRESERVATION ACT, 1956

Alta

OIL AND GAS CONSERVATION BOARD

603 SIXTH AVENUE SOUTH WEST • CALGARY 1, ALBERTA

REPORT TO

THE LIEUTENANT GOVERNOR IN COUNCIL

IN THE MATTER OF AN APPLICATION OF CONSOLIDATED NATURAL GAS LIMITED UNDER THE GAS RESOURCES PRESERVATION ACT, 1956

DECEMBER, 1969

OIL AND GAS CONSERVATION BOARD

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I INTRODUCTION

The subject application, made by Consolidated Natural Gas Limited under The Gas Resources Preservation Act, 1956, was heard by the Oil and Gas Conservation Board on July 2 to July 4, 1969, inclusive, with G. W. Govier, P. Eng., A. F. Manyluk, P. Eng., and Vernon Millard sitting.

In its application, Consolidated identified itself as a subsidiary of Northern Natural Gas Company (herein referred to as "Northern Natural"), a Delaware corporation, and as a Canadian body corporate having authority inter alia to deal in and process natural gas and related hydrocarbons.

Consolidated's application asked for a permit authorizing removal of 2.3 trillion cubic feet of gas from the Province of Alberta over the term of the permit. The proposed sources of the gas to be removed were the Strachan-Ricinus-Phoenix areas and the Kaybob South Beaverhill Lake A Pool. Further particulars regarding the application are presented in Section II of this report.

Date of Reserve Assessment and Period of Protection

The application contained Consolidated's estimate of reserves as of April 30, 1969. Amendments submitted by the applicant contained reserves data obtained as late as June, 1969, for certain pools. The Board has assessed the reserves of the Province as of May 31, 1969, the date it used in a recent report upon an application by Trans-Canada Pipe Lines Limited for removal of gas from the Province. Consistent with its previous practice, the Board

considered data available after the stipulated reserves assessment date that have an important bearing on the total provincial reserves or the application.

The period for which the Board has assessed the requirements of the Province and permit commitments is 30 years commencing June 1, 1969.

Standard Conditions of Measurement

Unless otherwise stated, volumes of gas given in this report are those at the standard conditions of 14.65 pounds per square inch absolute and 60 degrees Fahrenheit.

Where reserves of gas are referred to herein, it means unless otherwise specified, marketable reserves.

Appearances

The persons listed in Table I appeared at the hearing.

Alberta and Southern Gas Co. Ltd., Canadian-Montana Pipe Line Company, Triad Oil Co. Ltd. and Westcoast Transmission Company Limited appeared for the purpose of cross-examination and argument only.

TABLE I

APPEARANCES

	Abbreviation of Name Used in Report	Represented By	Witnesses
Consolidated Natural Gas Limited	Consolidated	J. H. Laycraft, Q.C. G. D. Nichols	N. J. Lashuk, P.Eng. J. T. Raleigh, P.Eng. A. T. C. Rutgers, P. Geol. R. F. Garfoot J. E. Holdeman J. R. Brady J. E. Moylan R. LoChiano R. E. Peirce J. C. Plourde H. R. Sampson All of Consolidated or Northern Natural J. E. Michaud, P. Eng. B. Balaz, P. Eng. S. L. Ozar, P. Eng. All of James A. Lewis Engineering Co. Ltd. D. H. Hushion of The Alberta Gas Trunk Line Company Limited
Alberta and Southern Gas Co. Ltd.	Alberta and Southern	R.A. MacKimmie, Q.C.	
Amerada Petroleum Corporation	Amerada	R.P.Cummer, P.Eng.	R. P. Cummer, P.Eng. E. N. Patton
Amoco Canada Petroleum Company Ltd.	Amoco	G. E. Little	G. M. Chernoff, P. Eng.

TABLE I (Cont'd)

	Abbreviation of Name Used in Report	Represented By	Witnesses
Banff Oil Ltd. and Aquitaine Company of Canada Ltd.	Banff	C.V. Kloepfer, P. Geoph.	C. V. Kloepfer, P. Geoph.
Canadian Fina Oil Limited	Canadian Fina	G. W. Brown	J. E. Baugh, P.Eng.
Canadian-Montana Pipe Line Company	Canadian-Montana	C. M. Leitch, Q.C.	
Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited	Utility Companies	G.A.C. Steer, Q.C.	J. E. Maybin, P. Eng.
City of Calgary	City of Calgary	S. J. Helman, Q.C.	D. L. Flock, P. Eng.
City of Edmonton	City of Edmonton	A. F. Macdonald, Q.C.	D. L. Flock, P. Eng.
Hudson's Bay Oil and Gas Company Limited	Hudson's Bay	L. B. Bannicke	D. C. Jones, P. Eng.
Trans-Canada Pipe Lines Limited	Trans-Canada	J. M. Cameron R. J. Ludgate	L. H. Larson, P.Geol. G. V. Rehwald, P.Eng. A. F. van Everdingen G. W. Woods V. L. Horte, P.Eng.
Triad Oil Co. Ltd.	Triad	J. R. Lacey, P.Eng.	
Westcoast Transmission Company Limited	Westcoast	J. W. Lutes	

II SUBMISSION OF CONSOLIDATED NATURAL GAS LIMITED

Application for a Permit

Consolidated applied for a permit authorizing removal of gas from the Province under the following terms and conditions:

(1) The term of the permit shall be for a period of 25 years commencing January 1, 1971.

(2) The amount of gas which may be removed from the Province during the term of the permit shall not exceed 2.3 trillion cubic feet.

(3) The amount of gas which may be removed from the Province during any 12-month period commencing November 1 and any consecutive 24-hour period shall not exceed 120 billion cubic feet and 360 million cubic feet respectively.

(4) Only gas produced from the Strachan-Ricinus-Phoenix areas and the Kaybob South Beaverhill Lake Pool may be removed from the Province.

(5) Gas in the amount of 110 per cent of the maximum daily volume may be removed to alleviate temporary operating problems.

(6) Gas acquired by Consolidated in exchange for equivalent volumes of gas from pools, fields or areas named in the permit may be removed from the Province.

Consolidated stated that it was its intention to sell the gas removed under the permit to Northern Natural at a point on the

Canada-United States border near Oungre, Saskatchewan.

The produced gas would be delivered through facilities of The Alberta Gas Trunk Line Company Limited to Empress, Alberta, from which point it would be transported to Oungre by a major pipe line to be built by Consolidated Pipe Lines Company, an affiliate of the applicant. Gas acquired by Northern Natural in the Tiger Ridge area of Montana would be transported by a lateral line to be constructed by Consolidated's affiliates to a point on the main line near Swift Current, Saskatchewan.

A pipe line would be built by Northern Natural to deliver the combined gas stream from the Canadian border to a connection with its existing gas transmission system at North Branch, Minnesota.

The gas would ultimately be consumed in Northern Natural's market area in the United States mid-west, principally in Minnesota, Wisconsin and Michigan. Consolidated stated that gas would be made available along the route of the main pipe line to any person or community wishing to purchase it.

The applicant's submission included details concerning the design, construction and cost of the proposed new transmission facilities, and information concerning the cost of gas delivered to North Branch, Minnesota. Letters were filed respecting arrangements for the transmission of gas in Alberta and through the proposed main line facilities. The applicant also provided a schedule to be followed by the applicant and its affiliates in securing necessary governmental authorizations for gas export and import, and for construction and operation of pipe line facilities.

Reserves

Consolidated estimated the initial marketable reserves of gas in the fields applied for to be 4.3 trillion cubic feet. All of these reserves were considered by Consolidated to be proved reserves.

In assessing the total provincial reserves, Consolidated accepted the 1968 year-end estimates published by the Board in OGCB Report 69-18[1], except that it substituted its own estimates for five areas for which its current estimates differed from those of the Board. In this manner, the applicant estimated the remaining reserves of the Province, as of April 30, 1969, to be 44.7 trillion cubic feet, or the equivalent of 47.3 trillion cubic feet of 1,000 Btu gas. The 47.3 trillion cubic feet results from adding to the Board's December 31, 1968 estimate of 45.8 trillion cubic feet 1.9 trillion cubic feet as the estimated increase in reserves in the five areas, and subtracting 0.4 trillion cubic feet of gas produced since December 31, 1968.

Further discussion of Consolidated's reserve estimates and the comparative estimates of the Board is presented in Appendix A.

Reserves Under Contract

Consolidated submitted that 1,745 billion of the 4,310 billion cubic feet of gas in the fields applied for were contracted for by it. Some 920 billion cubic feet were said by Consolidated to be

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(1) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur, Province of Alberta. December 31, 1968.

under contract to others in those fields.

Mr. Lashuk, a witness for Consolidated, said that it was Consolidated's position that it had met what it understood to be the Board's policy that approximately 80 per cent or more of the gas applied for be under contract or committed in one form or another. He said that Consolidated and others had virtually all of the presently known reserves at Strachan under contract, but that it had only two-thirds of its requirements from Kaybob South "Area B" under contract. He said that most of the remaining reserves in "Area B" were not under contract to buyers at the time of the hearing. (For administrative reasons the Kaybob South Beaverhill Lake A Pool has been divided along the north boundary of Township 60, with Unit #1 to the north and "Area B" to the south.)

Copies of typical gas purchase contract forms were included in Consolidated's submission. The delivery rate specified in the contracts was one million cubic feet per day for each 7.3 billion cubic feet of reserves, subject to modifications for cycling project restrictions. A feature of the contracts was a prepayment provision whereby a deposit for gas to be supplied from developed reserves would be paid to the seller.

Deliverability

Consolidated stated that 2.3 trillion cubic feet of gas would be available to it from the Strachan-Ricinus and Kaybob South reserves during the life of the requested permit. Deliveries to Consolidated from Strachan-Ricinus would be at a maximum daily rate

of 123 million cubic feet per day for the first 12 years, and would decline to 37 million in the 25th year. Deliveries to Consolidated from Kaybob South were predicted by the applicant to be 75 million cubic feet per day for the initial five years then 150 and 300 million per day for successive five and nine year periods respectively, and then to decrease to 120 million per day in the final year.

The views of Consolidated regarding the quantities of gas deliverable to it are discussed further in Section IV.

Trend in Growth of Reserves

The applicant submitted that the long term annual growth rate of initial marketable reserves was 2.5 trillion cubic feet. No estimate was presented for the recent short term growth rate.

This matter is discussed further in Section IV.

Alberta Requirements

Consolidated undertook a projection of the population of Alberta, and estimated that the Province's population would grow at an average annual growth rate of 1.5 per cent to 2,425,000 persons by 1998. This forecast suggested to Consolidated that the 30-year domestic gas requirements of the Province would be somewhat less than the total estimated by the Board in its OGCB Report 68-A[2].

In estimating domestic gas requirements, Consolidated assumed that the proportion of the provincial population served by gas

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(2) Report of an Application by Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. November 1968.

and the level of per capita consumption would be slightly higher than estimated by the Board in its last analysis. Consolidated's estimates of commercial requirements were prepared in a manner similar to its domestic projection. The applicant adopted the Board's estimate of industrial requirements published in OGCB Report 68-A, with an adjustment to allow for additional processing plant shrinkage resulting from permits authorized since the preparation of that report.

Consolidated forecast that the total gas requirements of the Province over the 30-year period 1969 to 1998 inclusive would be some 14.5 trillion cubic feet. Further details of the applicant's forecast are given in Appendix C.

Deferred Reserves

Consolidated estimated that the total of deferred reserves of marketable gas at April 30, 1969, was 4,083 billion cubic feet. Of this total, 3,550 billion cubic feet were considered to be marketable within 30 years. Mr. Lashuk said that in light of the Board decision permitting sales of gas from the Kaybob South Field, its reserves were not considered by Consolidated to be deferred. In response to questions at the hearing, he said that most of the reserves at Kaybob South could be produced in the 25-year term of the requested permit, and said he believed that they should thus be treated the same as any other pool from which sales were permitted. He agreed that if a major part of the Kaybob reserves were withheld from production for more than 25 years because of cycling requirements, some of the remaining reserves

could be considered as deferred.

Mr. Lashuk stated that cycled gas from sources other than Kaybob South was not included by Consolidated in the contractable category in its submission.

Gas Held for Peak Day Protection for Existing Permits

Consolidated stated that in its opinion, it was no longer necessary to set aside a contractable requirement of 0.5 trillion cubic feet of cushion gas for protection of peak day requirements under Westcoast's Permit No. WC 59-3. This matter is discussed further in Section IV.

Heating Value Adjustments

Consolidated stated in its submission that since gas removal permits refer to volumes at the provincial border, and since the major pipe line streams would be further processed before leaving the Province, permit commitments should be calculated using the heating value of the gas at the provincial border rather than at the local plant or field gate as has been the Board's practice. It noted that the fuel needs and the shrinkage in gas volumes due to processing in the pipe line plants were included in Alberta's requirements.

In its application, Consolidated presented its estimates of the heating values of gas streams leaving the Province and the calculations it used to convert the volumes under each existing permit to a 1,000 Btu basis. The resulting total permit commitments of 1,000 Btu gas at April 30, 1969, were shown to be 26.5 trillion cubic feet.

Surplus

Consolidated estimated the overall surplus of 1,000 Btu gas at April 30, 1969, to be 10.1 trillion cubic feet. It determined the contractable surplus to be 3.5 trillion cubic feet and the future surplus to be 6.6 trillion cubic feet.

Inherent in Consolidated's estimate of surplus were the assumptions discussed previously regarding Alberta requirements, the trend in reserves growth, deferred reserves, cushion gas for Permit No. WC 59-3 and heating value adjustments for permit commitments. In its calculation of years of trend gas to be attributed to future reserves Consolidated adopted a period of 4.9 years which it said resulted from application of the years of trend gas formula proposed at a recent Board hearing of an application by the Alberta Division of the Canadian Petroleum Association.

Mr. Lashuk indicated that if, instead of using 4.9 years of trend gas, Consolidated used the Board's policy of two years of trend gas, the future surplus would become a future deficiency of 0.6 trillion cubic feet, and the overall surplus would become 2.9 trillion cubic feet.

Details of Consolidated's calculations of surplus appear in Appendix D.

Term of Permit Applied For

Consolidated asked that the term of the proposed permit be for 25 years commencing January 1, 1971. Mr. Sampson said at the hearing that if the Board saw fit to restrict the term to 25 years from the date of issue, Consolidated would have to live with the Board's decision. Further discussion of this matter

appears in Section IV of this report.

Preparedness of the Applicant to Proceed

Consolidated stated that the proposed project was economically viable and, assuming no extraordinary delays in receipt of necessary authorizations, project operations could be conducted according to its outlined schedule. Consolidated maintained that its position with respect to gas reserves and deliverability both in Alberta and Montana would support the design rates set out in the application. Consolidated submitted evidence that Northern Natural had guaranteed the financing required for the Canadian operations. It also submitted a financial statement as evidence that Northern Natural was capable of providing the necessary financial backing.

This matter is discussed further in Section IV.

III SUBMISSIONS OF INTERVENERS

Amerada Petroleum Corporation

Amerada submitted a gas reserve estimate for the Strachan D-3 Pool indicating proved reserves of 1,593 billion cubic feet. The estimate had been previously submitted by Gulf Oil Canada Limited at a recent Board hearing. Mr. Cummer of Amerada said that Amerada's staff had participated in the Strachan study and were qualified to use it in connection with the Consolidated application.

Banff Oil Ltd. and Aquitaine Company of Canada Ltd.

Banff stated that Consolidated's gas reserve estimate for the Strachan D-3 Pool reflected its present assessment. Mr. Kloepfer testified that Banff's estimate of reserves of the pool was 1,620 billion cubic feet.

Canadian Fina Oil Limited

Canadian Fina supported the Consolidated application. It said that the entry of Consolidated as a new competitive buyer would open a new large market area for Alberta gas. Competition would bring greater rewards to producers and this in turn would encourage gas exploration and cause an increase in related industry activities and in provincial revenues from royalties and bonuses.

Hudson's Bay Oil and Gas Company Limited

Hudson's Bay stated that, although other purchasers may be willing to serve the same market as Consolidated, the prepayment aspect of the contracts of Northern Natural would reduce the heavy

financial burden of the producer during the development of gas reserves and would encourage exploration and development programs.

Hudson's Bay expressed the opinion that Consolidated was competent and capable of carrying out its contract obligations, and it thus urged the Board to give favourable consideration to the Consolidated application.

Amoco Canada Petroleum Company Ltd.

In supporting the Consolidated application, Amoco said it believed it would be beneficial to have Consolidated as a third major gas purchaser in Alberta. The contract incentives offered by Consolidated would, said Amoco, result in an immediate increase in drilling activity and should increase the gas reserves of the Province. The economy would also benefit, it said.

Amoco stated that it was convinced that Consolidated, as an affiliate of Northern Natural, had the financial and technical means to make its proposed project feasible.

Trans-Canada Pipe Lines Limited

Trans-Canada submitted that the granting of Consolidated's application was not in the public interest and the application should be denied because Consolidated did not have available to it the volumes of gas applied for, the feasibility of the pipe line project was not demonstrated, and it would not be prudent for the Board to encourage such a project. With respect to the latter point, Trans-Canada contended that the volumes of gas estimated to be available from Alberta in the next 10 years would not

fully support market expansion and reserves replacement of existing major pipe line systems.

Trans-Canada estimated the total reserves in the pools from which Consolidated planned to purchase gas to be 3,865 billion cubic feet. The reserves which would produce gas under contract for sale to Consolidated in these pools were estimated by Trans-Canada to be 1,613 billion cubic feet, although only 908 billion cubic feet were considered by Trans-Canada to be available to Consolidated in the period to 1995. The intervener said the difference resulted from gas sales restrictions at Kaybob South due to gas cycling requirements. The matter of reserves under contract is discussed further in Section IV.

Trans-Canada disagreed with the applicant's estimates of deliverability of gas for which Consolidated has contracted in Kaybob South and Strachan-Ricinus. Trans-Canada estimated that a maximum daily volume of 41 million cubic feet of gas would be available to Consolidated from Kaybob South, while a maximum of 90 million cubic feet would come from Consolidated's Strachan supply. The subject of deliverability is discussed at greater length in Section IV.

With respect to the feasibility of the proposed Consolidated project, Trans-Canada stated that the reserves and deliverability of the Alberta and Montana sources under contract were inadequate to support the pipe line, and the cost of gas delivered at North Branch would be greatly in excess of that estimated by Consolidated. The feasibility of the project is discussed further in Section IV.

Trans-Canada submitted a table of the estimated future

availability of gas from Alberta, which it stated demonstrated that the amount of Alberta gas available in the next 10 years for non-Canadian markets would be 5.6 trillion cubic feet. Trans-Canada said that a new major pipe line would not be necessary to market the anticipated volumes of gas that will be developed in Alberta. It forecast that the surpluses which would develop would be insufficient to satisfy the markets already available through existing pipe lines.

Trans-Canada said the Board should consider whether there is a need for a major new gas pipe line in Alberta in so far as it affects the general interest of the Province. The matter of the need for another gas pipe line for removal of gas from the Province is discussed further in Section IV of this report.

With regard to the calculation of surplus, Trans-Canada argued that the Board should consider as contractable gas only that volume of gas from Kaybob South which could be produced from it pursuant to the Board's Decision 69-12(1) regarding the Chevron Standard Limited cycling scheme. It said that the allocation of a larger volume to the contractable category would require the Board to prejudge what must be the subject of future applications to the Board. Trans-Canada also stated that, because of the positions of Westcoast and Canadian Western Natural Gas Company Limited on the matter, the Board should consider as a "contractable requirement" the 0.5 trillion cubic feet of gas reserved as peak day deliverability protection to Permit No. WC 59-3. In any event, said Trans-Canada, any consideration of the matter should be the subject of a hearing at which all interested parties could

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(1) Gas Cycling Kaybob South Beaverhill Lake A Pool. July, 1969.

present their views. This matter is discussed further in Section IV.

Canadian Western Natural Gas Company Limited
and Northwestern Utilities, Limited

The submission of the Utility Companies stated that Consolidated's estimates of domestic and commercial requirements were the same as those of the Utility Companies.

In reference to peak day protection for Westcoast's Permit No. WC 59-3, the Utility Companies stated that they would not anticipate that Canadian Western Natural Gas Company Limited would be in a position to supply peak load gas from its sources through existing pipe line interconnections to make up any shortage which Westcoast might experience.

The Utility Companies gave evidence that an agreement has been made with Consolidated whereby the applicant would make gas available to the Utility Companies on essentially the same terms as other licensees have done. They said it would not be their normal practice to purchase gas from Consolidated except for resale in some small towns.

The Utility Companies said that the trend to prepayment provisions and higher rates of take being stipulated in gas purchase contracts could cause problems to the Utility Companies when they purchase gas in the future.

In their argument, the Utility Companies said that the amount of gas available from Kaybob South over the permit term would be 0.6 trillion cubic feet, not 2.6 trillion as stated by the applicant. The 0.6 trillion figure was obtained assuming

sales of 68 million cubic feet per day over the whole permit term. The Utility Companies also stated that since Consolidated has made no arrangements regarding peaking gas for Permit No. WC 59-3, the 0.5 trillion cubic feet reserved for this purpose should remain in the surplus calculation. The Utility Companies said that, assuming the other figures in Consolidated's surplus calculations are correct, the applicant's contractable surplus figure of 3.5 trillion cubic feet should be reduced by the above discrepancies of 0.5 trillion and 2.0 trillion cubic feet to a corrected value of 1.0 trillion cubic feet.

The Utility Companies contended that the substantial uncontracted holdings of Chevron Standard Limited at Kaybob South could not be considered to be available to Consolidated. The Utility Companies also stated that in view of the keen competition for gas, the Board should limit permit volumes to the amount expected to be available during the lesser of the term of the permit or the contract term. Further discussion of the Utility Companies' views on the amount of gas available to the applicant appears in Section IV.

The City of Calgary and The City of Edmonton

The submissions of Alberta's two major cities, herein referred to as the "Cities", were essentially the same, and the Cities called the same witness at the hearing.

The Cities doubted that Consolidated could justify the quantity of gas for which it applied if its sources now under contract were examined under the rules for surplus gas being applied

at the time of application. The Cities stated that any rule changes should be approved by the Board before being used.

Dr. Flock, the witness for the Cities, stated that the Cities favoured the use of no more than two or three years of trend gas in the future surplus calculation. They were opposed, he said, to the use of deferred gas in the contractable category. He said that Consolidated, in its deliverability schedule, had utilized deferred gas that was not under contract. He said that the Cities believed that 0.5 trillion cubic feet of gas should be held in the contractable category for protection of Westcoast's Permit No. WC 59-3 as authorized by the Board.

Dr. Flock said that if the basic data of the applicant were used but the present policy respecting the Westcoast permit cushion gas was retained and only gas under contract were included, the contractable surplus available in consideration of Consolidated's application would be 1.2 trillion cubic feet, compared with the applicant's estimate of 3.3 trillion cubic feet.

The City of Calgary argued that the application should be considered under rules already sanctioned by the Board. It contended that, on the basis of Trans-Canada's evidence, Consolidated had not established reserves necessary to support its application. The City of Calgary expressed its concern that the current practice of making advance payments to producers of gas may raise the price of gas to City consumers.

The City of Edmonton argued that the concerns expressed by Trans-Canada about the adequacy of reserves to support the application were reasonable and deserving of the closest study by the

Board. This City urged the Board to take a conservative view in its consideration of the application if there were doubts as to how much gas was available. This recommendation was especially valid, it said, because it was apparent that markets for Alberta's surplus gas were clearly assured.

Alberta and Southern Gas Co. Ltd.

Alberta and Southern argued that the application should be denied. It stated that Consolidated did not have sufficient Alberta gas available to it to support the project, and that the project was not economically feasible. A number of statements based on the evidence were presented in favour of each argument. These matters are discussed further in Section IV.

Canadian-Montana Pipe Line Company

Canadian-Montana argued that the Consolidated application should not be granted. It said that the Montana gas reserves available to the applicant have been grossly overstated by Consolidated. It also stated that Montana's gas reserves should be marketed in that State because Montana is a gas deficient area.

Canadian-Montana said that the evidence indicated that the price of Alberta gas to Northern Natural at North Branch would be more than twice the present cost to Northern Natural, assuming no gas from Montana.

Westcoast Transmission Company Limited

Westcoast submitted argument concerning the peak day deliverability protection for its Permit No. WC 59-3. It said that

the setting aside of the specified volume for this purpose had been Board practice from the outset and the practice was reconfirmed by the Board in a 1966 report.

Westcoast did not express an opinion as to whether a need remains for the peak day protection but it stated that its customers had not authorized it to concur in an alternate method of calculation of reserves available for removal under its permit. Further discussion of Westcoast's views appears in Section IV.

IV MATTERS OF SPECIAL CONCERN

The Board believes that a number of rather contentious matters arising out of the application are deserving of special consideration. These matters are discussed below as to the views of the applicant, the interveners and the Board.

Term of Permit Applied For

(1) Views of Consolidated

In its application, Consolidated applied for a permit that would run for a term of 25 years, commencing January 1, 1971. Consolidated's policy witness, Mr. Sampson, said he saw nothing unusual in having contracts with terms of 20 years, particularly where it was reasonable to expect that the contracting person would have the best opportunity to obtain any gas remaining to be taken at the termination of the contract. He said he did not think that Consolidated was asking the Board to extend the permit term to 26 or 27 years. He said that if the Board decided to make an alternative termination date, Consolidated would just have to live with it.

(2) Views of the Utility Companies

The Utility Companies argued that the applicant's contracts in Strachan and Kaybob South were for a primary term of 20 years, and that thereafter the Strachan contracts could be cancelled by either party on one year's notice. They said that the permit, if granted, should be for a term of 20 years because the primary term of the contracts was for 20 years.

(3) Views of the Board

It is the Board's policy to restrict the maximum term of a

permit to 25 years. In the case of a new project, the Board believes that it is reasonable that the permit term should commence on the date upon which the applicant specifies that gas deliveries should commence, provided that the pre-delivery period is no longer than is reasonably necessary to complete arrangements for and construction of project facilities. The Board agrees with Consolidated that the 20-year contracts adequately support a 25-year permit term.

The Board is, therefore, prepared to consider a permit with a term of 25 years beginning January 1, 1971.

Alberta Gas Under Contract and Available to the Applicant

(1) Views of Consolidated

Consolidated stated that it had some 1,745 billion cubic feet of the total of 2,300 billion cubic feet of gas applied for under contract. Accordingly, it contended that it had complied with the Board policy that approximately 80 per cent or more of the permit volumes applied for be under contract to the applicant. Consolidated stated that the 1,745 billion cubic feet of reserves under contract is made up of some 735 billion cubic feet committed to it in the Strachan-Ricinus-Phoenix area and 1,010 billion cubic feet in the Kaybob South Field. It said that an additional 10 billion cubic feet could become available to Consolidated from uncommitted reserves at Strachan. Consolidated considered it reasonable to assume that the remaining 545 billion cubic feet of gas applied for would become available to it from Kaybob South where its evidence indicated that, at the time of the hearing, 1,610 billion cubic feet of reserves remained uncommitted.

Consolidated submitted a detailed deliverability schedule for the Kaybob South Field and the Strachan-Ricinus-Phoenix area. The schedule indicated that Consolidated would have available from the Strachan-Ricinus-Phoenix area some 37 billion cubic feet per year during the first 14 years of the term of the permit applied for and that the volume would decline slowly thereafter. The schedule also showed that the gas available to Consolidated from Kaybob South would average some 25 billion cubic feet per year for the first five years of the term of the permit applied for and would double to some 50 billion cubic feet per year beginning in 1976. The schedule showed a further increase in the available gas to some 91 billion cubic feet per year beginning in 1981, remaining at that level through 1990 and declining thereafter. On the basis of the schedule, Consolidated concluded that during the term of the applied for permit, the entire 2.3 trillion cubic feet of gas could be produced and available to it.

Mr. Raleigh said that in determining the total deliverability of the Kaybob South Beaverhill Lake A Pool, well potentials were studied and a corresponding production rate was forecast in accordance with regulatory specifications regarding maximum production rates. The amount of gas which would be delivered from the total pool was determined assuming that gas sales from the entire pool would be permitted at the same sales rate per reserves that was approved by the Board for Area B in Decision 69-12(1).

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(1) Gas Cycling Kaybob South Beaverhill Lake A Pool. July 23, 1969.

Mr. Lashuk said that there were four reasons why deliveries from Kaybob South could increase in 1976:

(1) The demand for Alberta crude oil would likely be greater, permitting increased sales of pentanes plus and thus a higher cycling rate.

(2) The many wells in the pool could possibly be used to manipulate the dry gas front and thus reduce the volumes of dry gas injection required.

(3) Part of the pentanes plus which drops out in the reservoir due to pressure reduction would revapourize when contacted by dry gas, thus reducing the degree of pressure maintenance and increasing the availability of sales gas.

(4) Some pressure maintenance may be available from the associated aquifer.

Mr. Lashuk stated that the volumes of field deliverability after 1980 were determined assuming that cycling would be terminated having reached its economic limit, and that the total plant capacity of 785 million cubic feet of raw gas per day would be available. Since processing capacity was not a limitation, the rates were selected to deplete the reservoir during the remainder of the 25-year term of the permit applied for. Mr. Lashuk said that even if the now-approved 75 million cubic feet per day sales rate were continued for 15 years to 1985 and maximum plant capacity was utilized thereafter, some 93 per cent of the pool's marketable reserves would be delivered in the 25-year permit term.

In answer to questions, Mr. Lashuk conceded that Consolidated would need to contract to buy considerably more gas at Kaybob South

to obtain the 75 million cubic feet per day. He agreed that the Board must recognize circumstances at the time of application and cannot ignore the limitation of average daily gas sales to 75 million cubic feet per day in all of Area B at Kaybob South.

(2) Views of Trans-Canada

Trans-Canada estimated that the gas reserves under contract to Consolidated totalled some 1,613 billion cubic feet made up of about 1,076 billion cubic feet at Kaybob South and some 537 billion cubic feet in the Strachan-Ricinus-Phoenix area. The total amount available to Consolidated during the period to 1995 was estimated by Trans-Canada to be 908 billion cubic feet. The difference of 705 billion cubic feet was said to be the quantity of gas at Kaybob South which was under sales contract to Consolidated but unavailable to it due to the restriction of gas sales from the pool. Trans-Canada stated that the Board could only consider as being available to the applicant for permit purposes the lesser of the volume under contract in a field or the volume which the applicant could reasonably expect to withdraw from the field during the permit term.

Trans-Canada submitted an alternative deliverability schedule for the areas from which Consolidated proposed to obtain its gas. The schedule indicated that the gas available to Consolidated from the Strachan-Ricinus-Phoenix area would be some 27 billion cubic feet per year for the period 1971 to 1986 inclusive and would decline thereafter until the pools were depleted in about 1993. The gas available from the Kaybob South Field would, in Trans-Canada's submission, remain constant at some 15 billion cubic feet per year throughout the term of the permit applied for.

(3) Views of the Utility Companies

The Utility Companies argued that the cycling period of the Chevron Standard Limited cycling scheme at Kaybob South was indicated by the operator of the scheme to be 18 to 21 years. Making the assumption that only some 38 million cubic feet per day from the scheme could be considered available to Consolidated, the Utility Companies estimated the gas available to the applicant from Kaybob South over the period of the proposed permit to be 0.3 trillion cubic feet. The Utility Companies said that, assuming that the applicant's evidence relating to reserves was satisfactory, the total reserves available to support the proposed permit including those of the Strachan area would be 1.0 trillion cubic feet.

(4) Views of the Cities

The Cities of Calgary and Edmonton expressed doubt that Consolidated had sufficient reserves to support its application. They said that they relied upon evidence submitted by Trans-Canada to support their position on this matter.

(5) Views of Alberta and Southern

Alberta and Southern submitted that Consolidated had not proved that it had secured volumes of deliverable gas sufficient to support the permit quantities applied for. This intervener observed that the applicant's estimate of annual volumes available were as low as 62 billion cubic feet, compared with the 120 billion cubic feet applied for. It further submitted that the difference between these amounts would be increased by the amount of gas used in Trunk Line operations.

Alberta and Southern stated that there was no satisfactory evidence to justify a doubling of gas sales from Kaybob South in the years 1976 to 1980 as shown by Consolidated. It said further that "this is the first application where serious deliverability deficiencies show up in each of the initial 10 years".

(6) Views of the Board

The Board has considered the evidence respecting the reserves and the contractual situation in the Strachan-Ricinus-Phoenix area and the Kaybob South Field as put forward by the applicant and the interveners at both the subject hearing and the earlier hearing of an application by Trans-Canada. The Board has combined the submitted evidence respecting contracts and its own estimate of the reserves which are described in greater detail in Appendix A, to determine the gas under contract to Consolidated.

With respect to the Strachan-Ricinus-Phoenix area, the Board concludes that some 621 billion cubic feet, or some 42 per cent of the total reserves are under contract to Consolidated in the two pools in this area.

The Board has also reviewed the evidence and limited field data regarding the deliverability of these pools and recognizes difficulties in projecting future deliveries from them. On the basis of its assessment, the Board believes that the pools could deliver gas in the initial 15 years of production at the rate of 1 million cubic feet per day for each 7.9 billion cubic feet of reserves. This is the rate used by both Consolidated and Trans-Canada in their detailed deliverability schedules. On this basis and using its own estimate of reserves, the Board believes that

the average combined production rate for the two pools would be about 190 million cubic feet per day or 70 billion cubic feet per year. Assuming a declining rate in the latter ten years of the production period, the Board believes that the reserves could be essentially depleted in the 25-year term of the applied for permit.

Dealing now with the Kaybob South Field, the Board, on the basis of its assessment of submitted evidence, concludes that the total gas actually under contract to Consolidated at Kaybob South is some 970 billion cubic feet. This represents approximately 46 per cent of the total pool reserves of 2,100 billion cubic feet.

The Board has also considered whether all of the reserves under contract to Consolidated could be included in a permit after application of the procedures outlined in OGCB 69-D[2] respecting the treatment of deferred reserves. The report states that the Board believes it would be proper to treat as contractable reserves

(a) a deferred reserve from which initial production is certain to begin within three years, or

(b) a deferred reserve, under contract and included in a permit or an application for permit if initial production could be expected within a reasonable period.

The report states further, respecting the portion of a de-

(2) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October 1969.

ferred reserve to be considered as contractable, that the Board is prepared to consider as the contractable portion that part of the reserve which could reasonably be produced during the period in question.

While the Kaybob South Beaverhill Lake A Pool is being cycled, the Board has approved a sales rate of 75 million cubic feet per day and believes that a share of this production would be available to the applicant during the initial years of the period being considered. The Board has received considerable evidence respecting recoveries from the pool under various methods of production, at hearings related to the cycling of the pool. On the basis of this evidence and its own knowledge of the pool, the Board believes a reasonable production prediction is possible. Since a portion of the reserve is under contract and included as part of the basis for the subject application the Board is prepared to consider as available to Consolidated certain reserves in addition to those currently approved for production.

The Board notes that the contracts in the area reflect a sales rate of at least 1 million cubic feet per day for each 7.3 billion cubic feet of reserves. The corresponding sales rate for the entire pool is some 288 million cubic feet per day. There is uncertainty as to when such a sales rate from the pool may be reached and also as to whether or not the rate can be sustained over a long period or possibly even be exceeded. All things considered, the Board is prepared to consider as producible, the production equivalent to that which would result if an average rate of 75 million cubic feet per day were sustained for 10 years beginning

in the year 1970 and a rate averaging 288 million cubic feet per day were maintained for 15 years thereafter. The forecast production rate of 288 million cubic feet per day is then arbitrarily reduced to an average of 75 million cubic feet per day (the sales rate now approved) for the final five years of the 30-year protection period.

The Board recognizes that sales of 288 million cubic feet per day may not be attained in one additional incremental step, and in fact may not be reached within the next 10 years. It also recognizes that sales may not be sustainable at this level for 15 years once it has been reached. However, the Board believes that the characteristics of the reservoir and the capacity of physical facilities are such that a sales rate in excess of 288 million cubic feet per day may, if necessary, be attained for at least a number of years after full sales are approved. In summary, while the pattern of production may not coincide with that described earlier, the Board is confident that the resulting total production is reasonable.

It should be emphasized that the Board is not at this time approving additional sales beyond 75 million cubic feet per day for any particular time. Applications for additional sales from the pool will be assessed under The Oil and Gas Conservation Act at such time as they are received by the Board. The Board will from time to time and on the basis of the most recent information available to it, review its production forecast for the pool and take account of such information in its analysis of applications for new permits or amendments to existing permits to remove gas from the Province.

On the basis of a production rate averaging 75 million cubic feet per day over the period 1970 to 1979 inclusive, an average rate of 288 million cubic feet per day for the following 15 years and an average rate of 75 million cubic feet per day thereafter, the Board predicts that production from the pool will amount to some 1,985 billion cubic feet by the end of 1999. Of this, the Board estimates that some 914 billion cubic feet will be available to Consolidated during the term of its applied for permit. This compares with the 970 billion cubic feet which the Board estimates is actually under contract to Consolidated.

The Board thus estimates the gas available to Consolidated in support of its application to be 1,535 billion cubic feet comprising 621 and 914 billion cubic feet respectively in the Strachan-Ricinus-Phoenix area and the Kaybob South Field. The total volume under contract and available to Consolidated represents 67 per cent of the volume applied for.

As calculated by the Board, the total amount of gas available to Consolidated on an average daily basis would be approximately 120 million cubic feet per day in years 1 to 10, 220 million cubic feet per day in years 11 to 15, and would decline slowly thereafter. Accordingly, the Board concludes that essentially all of the reduced volume of some 1,535 billion cubic feet could be delivered during the term of the applied for permit.

<u>Peak Day Protection for Permit No. WC 59-3</u>

(1) Views of Consolidated

Consolidated submitted that it was no longer necessary to set aside as a contractable requirement the reserves necess-

ary to meet the peak-day requirement in the Westcoast Permit No. WC 59-3. It based its position on the availability of excess reserves in the permit pools, the contract condition giving Westcoast first call on deliverability from certain reserves under contract to Trans-Canada, and the connection of facilities supplying Westcoast to facilities supplying local utilities. Consolidated stated that it had not consulted with Westcoast or other parties respecting this matter.

(2) Views of Interveners

Trans-Canada, the Utility Companies, the Cities of Calgary and Edmonton, and Westcoast all opposed the suggestion of Consolidated that peak-day protection for the Westcoast Permit No. WC 59-3 be removed. The opposition was for a variety of reasons, but the interveners appeared to agree that the removal of this protection without prior application by the permittee would not be consistent with the historical administration of The Gas Resources Preservation Act, 1956.

(3) Views of the Board

In keeping with a decision announced in OGCB 69-D, the Board will retain provision to meet the terminal year peak-day for certain permits. These will include permits such as Permit No. WC 59-3 where calculations published by the Board have included some quantity of gas to provide for the terminal year peak-day and where the permittee has not subsequently agreed to the discontinuance of this provision.

Feasibility of the Project

(1) Views of Consolidated

Consolidated stated that through its affiliation with Northern Natural it had the necessary financial and other resources to carry out the project as planned. Consolidated submitted evidence to support its position that the volumes of gas available in support of the project from Alberta and Montana were sufficient to ensure that gas could be provided to Northern Natural at rates consistent with Northern Natural's current rate structure and gas supply objectives.

Consolidated indicated that the pipe line would be built on the expectation that future reserves would be available to it. It said that the proposed pipe line size could be reduced prior to construction if it appeared that future volumes would be smaller than anticipated.

Consolidated opposed a conclusion by Trans-Canada that insufficient gas would be available in the future to support the proposed project.

(2) Views of Hudson's Bay and Amoco

Hudson's Bay and Amoco testified that, in their opinions, Consolidated had the means and capability of carrying out its plans.

(3) Views of Trans-Canada

Trans-Canada contended that Consolidated had grossly overstated the volumes of gas available to it from Alberta and Montana. Trans-Canada also contested some of the cost estimates used by Consolidated in its economic analysis and said that the cost of

gas to Northern Natural would be much higher than that indicated by Consolidated. The intervener submitted evidence with regard to both matters.

Trans-Canada stated that the total volume of gas likely to be available for removal from Alberta in the next 10 years after accommodating increases in Canadian markets would be insufficient to support the large facilities proposed by Consolidated.

(4) Views of Alberta and Southern

Alberta and Southern stated that no area of economic feasibility was proven in the application and said that the proposed project had no chance of success based upon the reserves under contract. The intervener stated that possible future gas supplies in Canada's far north should not be considered as part of the project gas supply.

(5) Views of the Board

The Board does not consider it incumbent upon it to rule in an absolute sense on the project feasibility even though it does have a general interest in the scope and feasibility of the proposed project. The Board's interest respecting feasibility is primarily to avoid a situation whereby an applicant might tie up reserves, through their inclusion in a permit, when the scheme to which the reserves are dedicated has little prospect to proceed. This could result in the withholding of reserves, on at least a temporary basis, from other existing or proposed schemes. Such an occurrence might not be in the public interest.

The Board believes that Consolidated, in affiliation with Northern Natural, has the economic and technical resources to construct the proposed facilities. It agrees with several interveners that the quantities of gas currently under contract to Consolidated and available to support the proposed project are deficient. However, the Board recognizes that the application is predicated on the expectation that future reserves would be available to the applicant in Alberta and beyond, and consequently the feasibility of the project should not be considered by reference only to reserves included in the current application.

All things considered, the Board is satisfied that the evidence brought forward by Consolidated of the feasibility of the scheme is such that a permit should not be withheld on the basis of feasibility considerations. It is the Board's view that any permit granted should contain a performance condition regarding the date of the commencement of construction of project facilities.

The Need for a Major New Pipe Line to Remove Gas From the Province

The question of whether or not it would be in the public interest to permit the construction of another major pipe line to remove gas from the Province was raised by Trans-Canada.

(1) Views of Trans-Canada

Trans-Canada stated that the estimated future development of gas reserves in Alberta did not justify a new pipe line project out of Alberta, having regard for the requirements of Alberta and of existing pipe lines dependent upon Alberta for their gas supply.

Trans-Canada estimated that some 17.6 trillion cubic feet of gas would become available for removal from Alberta over the next 10 years and that 12.0 trillion of this would be required to serve increasing Canadian markets, with the balance of 5.6 trillion being available for export to the United States.

Mr. Horte said that the surpluses which would be developed in Alberta would not be sufficient to handle the markets already developed. He said that Consolidated was looking to the future reserves to support and fill its pipe line, and that it would be well to look at the future in light of all expectations. He suggested that the orderly marketing of gas was important to the Province, and that the Board was under no obligation to grant permits in a situation where there were a number of partly filled pipe lines.

In its argument, Trans-Canada stated that to encourage another export-oriented line in the present situation would create pressures on the Province to revise its policy of protecting Alberta gas consumers or to make all future gas available to the applicant to the exclusion of existing pipe line companies.

Mr. Horte said that he had not changed a view he had previously expressed that 240 trillion cubic feet of gas could reasonably be expected to be developed in that part of the Western Canada sedimentary basin that is contained in the western provinces. He admitted that it was a possibility that the existence of a new gas purchaser might quicken the development of the potential reserves.

When asked if he was suggesting that no person but Trans-Canada should be permitted to move gas eastward from Alberta, Mr. Horte said he was not. He said that the expanding existing markets plus the replacement of reserves to serve them would place heavy demands on Alberta's reserves. He drew a parallel to the situation in the United States where, he said, the reserves were having a difficult time looking after the existing market, and would not support additional markets. To further questions he said that Trans-Canada was hoping to initiate the sale of Alberta gas in the Chicago area. He said that he was not proposing that only existing markets be served, but he was pointing out the realities of the future Canadian needs for gas, the volumes left over for export to the United States, and the perspective with respect to a new major pipe line. He said that Alberta was the only source he knew of to supply Canadian markets east of Alberta.

Mr. Horte said he was certain that the matter of the need for another gas export pipe line fell within the area of interest of the National Energy Board, but was less certain of the involvement of the Province of Alberta.

(2) Views of Consolidated

Consolidated contested the position adopted by Trans-Canada that the estimated future development of gas reserves in the Province does not justify a new pipe line to remove gas from Alberta. Consolidated stated that the principal purpose of Trans-Canada's opposition to the application was "to preserve and extend its monopoly position as the sole exporter of gas eastward from Alberta to any other point in North America".

It said that the estimates and statements presented by Trans-Canada on future volumes of gas available for removal from Alberta could be explained only by assuming:

"1. With priority given to the Canadian market, all the Canadian market east of Alberta must be met by Alberta gas. Alberta will provide the stockpile for that Canadian requirement and Trans-Canada will then be free to acquire gas in other Canadian areas, such as the Northwest Territories, and export it to the United States.

2. With the Canadian priority and the Alberta stockpile to meet it, there will be an additional 5.6 Tcf of gas available to the end of 1979.

3. No one but existing exporters should be permitted to move that gas. Thus the Trans-Canada monopoly on movement eastward would be assured."

Consolidated stated that there was no reason to prefer one United States market area to another. It noted that no guarantees were attached to gas removal permits either for renewal of the permit or for expansion of the volumes stipulated therein. Consolidated said that it was even more evident that no company removing gas from Alberta had "any assurance of protection as a monopolist".

(3) Views of the Board

An expressed object of The Gas Resources Preservation Act, 1956 is to provide for the effective utilization of the oil and gas resources of Alberta having regard to the needs of persons

within the Province. Further the Act prohibits the granting of a permit unless the Board is of the opinion that it is in the public interest having regard to the present and future needs of those within the Province and to the reserves and trends in growth and discovery of reserves of gas within the Province.

The Board does not believe that the granting of a permit to Consolidated would have an adverse effect on the utilization of the Province's gas resources. Further, it believes that access to markets of Northern Natural might spur development of gas resources in Alberta and elsewhere in Canada.

The Board agrees with Consolidated that a permit authorizing the removal of gas from the Province carries with it no guarantee as to extension or expansion. The Board recognizes that a permit granted to Consolidated could give rise to pressures of the type referred to by Trans-Canada, but in view of the provisions of The Gas Resources Preservation Act, 1956 and the policies and procedures that have been developed under the Act, the Board sees no way in which the pressures could adversely affect the protection of provincial requirements or the consideration of applications of other permittees.

In considering the effect of a proposed permit on the public interest, the Board's responsibility, having regard to provincial requirements and reserves, relates largely to determining if there is a surplus after providing for provincial requirements and permit commitments. The Board would not be concerned about other matters affecting the public interest unless there was strong evidence of adverse effects, and the Board finds no such evidence upon the present application.

The Board notes that Trans-Canada estimated that only a limited amount of the gas which can be expected to be surplus to Alberta's requirements will, under National Energy Board policies, be available for export. The provision for the requirements of Canada exclusive of Alberta, however, is a matter within jurisdiction of the National Energy Board and not the Alberta Oil and Gas Conservation Board. This Board therefore considers that it would be improper for it to withhold a permit for the removal of gas from Alberta on the basis that the gas might be required for other Canadian markets.

In summary the Board does not consider that it should withhold a permit upon the ground that a new pipe line for the removal of gas from the Province is not justified.

V FINDINGS

The Board having heard publicly the application under The Gas Resources Preservation Act, 1956, of Consolidated Natural Gas Limited, and having studied the evidence submitted by the applicant and the interveners at the public hearing, and having regard to the advice of its staff and to its own knowledge, finds as follows:

1. THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates the established reserves of marketable gas remaining in the Province at May 31, 1969, to be some 44.3 trillion cubic feet, or the equivalent of 46.8 trillion cubic feet of 1,000 Btu gas.

Of the latter total some 2.9 trillion cubic feet are now considered to be beyond economic reach and some 4.3 trillion cubic feet will have production deferred, leaving a contractable reserve of 39.6 trillion cubic feet of 1,000 Btu gas.

The present estimate of 46.8 trillion cubic feet is some 1.0 trillion cubic feet more than the Board's estimate at December 31, 1968. The increase is largely due to development drilling and to evaluation of reserves from pool performance where significant pressure and production data has become available.

Details of the Board's estimate and a discussion of the more significant changes since the Board's analysis as at December 31, 1968, are presented in Appendix A.

2. THE LONG TERM GROWTH OF RESERVES OF GAS IN ALBERTA AND THE FUTURE RESERVES TO BE CONSIDERED

The long term growth of initial marketable reserves of gas due to new discoveries and to appreciation of previous discoveries has continued to average some 2.5 trillion cubic feet per year determined on the basis used in previous reports. However, the Board indicated in its report OGCB 69-D(1) that it would use a growth rate determined from growth over the immediately preceding 10 years to determine the growth of gas reserves to be considered in determining the relationships of future reserves to future requirements. The Board did not make an estimate of the reserves of the Province at May 31, 1959. However, during the 116-month period, September 30, 1959 to May 31, 1969, reserves increased by 25.2 trillion cubic feet, equivalent to 2.6 trillion cubic feet per year.

The Board also indicated in OGCB 69-D that it would determine the number of years of growth of gas reserves used in the surplus calculation on the basis of the Province's estimated remaining reserve potential. The formula adopted by the Board results in the use of 4.5 years of reserve growth.

Since the growth rates over the last five years and over the last two years have averaged 3.0 trillion cubic feet per year and 3.6 trillion cubic feet per year respectively, and having regard for other relevant factors, the Board estimates the average

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(1) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October 1969.

growth rate of initial gas reserves over the next 4.5-year period as 2.6 trillion cubic feet per year.

Under the policy set forth in OGCB 69-D, the Board in the present circumstances therefore recognizes 11.7 trillion cubic feet of future gas reserves comprising 4.5 years of growth in determining the relationship between future reserves and future requirements. Particulars of the determination of these volumes are set forth in Appendix B.

3. THE PRESENT AND FUTURE REQUIREMENTS FOR GAS AND THE PRESENT PERMIT COMMITMENTS

The Board estimates Alberta's requirements for the 30 years, June 1, 1969, to May 31, 1999, to be 15.7 trillion cubic feet of 1,000 Btu gas, with a peak day requirement in the 30th year of 3.5 billion cubic feet. The present estimate represents an increase of 1.1 trillion cubic feet in the total 30-year requirements since the Board's last estimate, which was for the period, September 1, 1968, to August 31, 1998.

The commitments remaining at May 31, 1969, associated with permits issued for removal of gas from the Province, total some 26.1 trillion cubic feet of 1,000 Btu gas. After including the approximately 2.2 trillion cubic feet recently approved for removal by Trans-Canada, the total commitments become 28.3 trillion cubic feet.

Details of the Board's estimates of Alberta's requirements and permit commitments are presented in Appendix C.

4. THE MEETING OF ALBERTA'S 30-YEAR REQUIREMENTS AND PRESENT PERMIT COMMITMENTS, AND THE RESULTING SURPLUS

The Board estimates that reserves totalling some 20.7 trillion cubic feet of 1,000 Btu gas are necessary to meet the annual and peak day requirements of Alberta for the 30-year period, June 1, 1969, to May 31, 1999. Of this total, 15.7 trillion cubic feet are required for actual deliveries and the remaining 5.0 trillion cubic feet are needed to meet the 30th-year peak day.

The Board's estimate of 20.7 trillion cubic feet may be considered to consist of 8.1 trillion cubic feet of contractable requirements and 12.6 trillion cubic feet of remaining requirements, the latter being a measure of the reserves needed from sources not now under contract or connected to the Alberta market.

The Board estimates that 28.6 trillion cubic feet of 1,000 Btu gas are required to meet the present permit commitments, including those resulting from the granting of the recent Trans-Canada application. Of this amount, some 0.3 trillion cubic feet represent the reserves needed to ensure deliverability in the terminal year for those permits under which it is contemplated that substantial daily withdrawals for which protection has historically been provided will continue to the end of the term.

When the contractable requirement of 8.1 trillion cubic feet and the gas needed to satisfy the permit commitments of 28.6 trillion cubic feet are deducted from the contractable reserve of 39.6 trillion cubic feet, a contractable surplus of 2.9 trillion cubic feet results.

The remaining and future reserves totalling some 18.5 trillion cubic feet consist of 4.3 trillion cubic feet of deferred gas which will be available within the 30-year period, 2.2 trillion cubic feet of gas now beyond economic reach but which the Board believes will be within economic reach and available within 30 years, 0.3 trillion cubic feet of reserves allocated to provide for the peak day in permits which will be available at the termination of the permits and within 30 years, and 11.7 trillion cubic feet representing 4.5 years of growth of gas reserves at a growth rate of 2.6 trillion cubic feet per year. Comparing the total with the 12.6 trillion cubic feet of remaining Alberta requirements results in a surplus of 5.9 trillion cubic feet in the future category. This results after full provision for the 3.0 trillion cubic feet required from sources not now connected to meet Alberta's 30th-year peak day.

Details of the Board's analysis of these matters appear in Appendix D.

5. THE TERM OF THE PERMIT APPLIED FOR

The Board finds in favour of the applicant's submission that the period of the proposed permit be from January 1, 1971, to December 31, 1995. This matter is discussed in Section IV.

6. THE VOLUMES UNDER CONTRACT AND THE PERMIT VOLUMES APPLIED FOR

Consolidated stated that it had under contract some 1,745 billion cubic feet of the 2,300 billion cubic feet of gas applied

for. The Board disagrees with Consolidated's estimates and finds that the gas under contract and available to Consolidated under the Board's category of contractable reserves over the permit term are some 1,535 billion cubic feet or 1,679 billion cubic feet of 1,000 Btu per cubic foot gas.

Details of the Board's analysis of this matter are presented in Section IV and Appendix E.

7. THE FEASIBILITY OF THE PROPOSED PROJECT

While the Board does not consider it to be its responsibility to rule in any absolute sense on the economic feasibility of the proposed project, it finds that there are no technical or economic feasibility considerations that should stand in the way of granting the permit applied for. The Board has decided that should a permit be granted, it should contain a condition requiring that the Board be satisfied by July 1, 1970 that the construction of project facilities will commence by January 1, 1971.

This matter is discussed in Section IV.

8. THE NEED FOR A MAJOR NEW PIPE LINE TO REMOVE GAS FROM THE PROVINCE

The Board, having reviewed its responsibility in the matter and having considered the evidence, finds that there is no reason why it should withhold the granting of a permit to the applicant on the grounds that the construction of a major new pipe line to remove gas from the Province is unjustified.

This matter is discussed in Section IV.

9. THE APPLICATION FOR REMOVAL OF GAS AND THE SURPLUS WHICH WOULD RESULT IF THE APPLICATION WERE GRANTED

The Board has found that the applicant has available to it over the proposed permit term some 1,679 billion cubic feet of 1,000 Btu gas. If the application were granted in accordance with this reduced volume, the reserves needed to meet the commitment of all permits, including that resulting from the recent approval of the Trans-Canada application, would increase from 28.6 trillion cubic feet to 30.3 trillion cubic feet. The contractable surplus would be reduced from 2.9 trillion cubic feet to 1.2 trillion cubic feet, while the future surplus would remain unchanged at 5.9 trillion cubic feet.

The Board thus finds that the applied for volumes of gas, reduced in accordance with Finding 6, are surplus to the requirements of the Province and the present permit commitments. The Board is satisfied that essentially all of the gas could be produced within a 25-year term.

The Board finds it appropriate to reduce in proportion to the reduction in total volume the maximum daily rate applied for. The latter thus becomes some 263 million cubic feet per day on the basis of 1,000 Btu per cubic foot. While this rate would be larger than required in the first 15 permit years, the Board sees no advantage in setting a reduced maximum rate for that period.

Details of the Board's analysis of these matters are presented in Appendix E.

10. THE DISPOSITION OF THE APPLICATION OF CONSOLIDATED NATURAL GAS LIMITED

In light of its findings and its responsibilities under the Act, the Board is prepared, with the approval of the Lieutenant Governor in Council, to issue a permit authorizing the removal by Consolidated Natural Gas Limited of 1,535 billion cubic feet of gas from the fields and areas applied for, the permit to be in the form shown in Appendix F and subject to the terms and conditions therein contained.

Respectfully submitted,

G. W. Govier, P. Eng.
Chairman

Vernon Millard
Board Member

Dated at Calgary, Alberta

this 15th day of December, A.D. 1969.

APPENDIX A

THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates the remaining established reserves of marketable gas in Alberta at May 31, 1969, were 44.3 trillion cubic feet, or the equivalent of 46.8 trillion cubic feet of 1,000 Btu gas. The initial established reserves obtained by adding the cumulative production to May 31, 1969 of 8.9 trillion cubic feet were 53.2 trillion cubic feet. The estimate of remaining established reserves represents an increase on an actual heating value basis of some 1.0 trillion cubic feet since December 31, 1968, when the Board's estimate was 43.4 trillion cubic feet. On an actual heating value basis, Consolidated estimated that the remaining established reserves at April 30, 1969, were 44.7 trillion cubic feet. Consolidated submitted reserve estimates for three fields from which it has contracted to purchase gas, and for certain other fields where significant increases had occurred since the Board's assessment of December 31, 1968, published in OGCB Report 69-18[1].

While only the established reserves are discussed in this report, the Board has calculated proved and probable reserves of gas. The definitions and interrelationships of these categories of reserves are as follows:

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(1) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur, Province of Alberta. December 31, 1968.

<u>Proved Reserves</u> are the recoverable gas reserves within the area of a pool completely delineated by drilled wells. A portion of such reserves may be in undrilled drilling spacing units but so located structurally that there is every reasonable probability that the reserves will be produced by wells drilled or to be drilled.

<u>Probable Reserves</u> are the reserves of gas estimated to be recoverable from the pool beyond the proved limits of the pool. The probable pool limits are based on normal geological expectation.

<u>Established Reserves</u> are the reserves of gas whose existence and estimated amount can reasonably be counted upon. They include all of the proved reserves and a judgment portion (usually 50 per cent) of the probable reserves.

In its estimate of reserves, the Board has had regard for the estimates presented by the applicant and interveners at the hearing, the estimates included in various submissions presented recently to the Board, and evaluations made by its staff. The staff has reviewed all estimates submitted by the applicant and the interveners as well as its own previous estimates where desirable because of production history, additional drilling, or other new data.

The majority of the increases in the Board's estimates of remaining marketable reserves in the five-month period ending May 31, 1969, were the result of successful development drilling in various pools, and the majority of the reductions were due

to the production of gas during the period.

A comparison of the Board's reserve estimates for the year ending December 31, 1968, and at May 31, 1969, follows:

	Actual Basis	1,000 Btu Basis
	(Trillions of Cubic Feet)	
Remaining Established Reserves of Marketable Gas at December 31, 1968	43.4	45.8
Net Additions to Reserves	1.4	1.5
Marketable Gas Produced	0.5	0.5
Remaining Established Reserves of Marketable Gas at May 31, 1969	44.3	46.8

The following tabulation lists some of the larger pools or strata for which there have been significant changes in the Board's estimates of initial marketable reserves (unadjusted for heating value) or for which there are significant differences between the Board's estimate and the reserve estimates of other interested parties:

Field or Area Pool or Stratum	Board's Estimate as of Dec. 31 1968	May 31 1969	Other Estimates as of May 31, 1969 Estimators	Estimates
Brazeau River Elkton A	450	480	Trans-Canada	460
Brazeau River Elkton B	140	180	Trans-Canada	244
Greencourt Pekisko A	62	85	Trans-Canada	83
Harmattan East Rundle	900	800	None	-
Kaybob South Beaverhill Lake A	1,800	2,100	Consolidated Trans-Canada	2,616 2,308
Obed D-2A	60	125	Trans-Canada	117
Provost Viking A and Viking B	900	900	Trans-Canada	1,001
Quirk Creek Rundle A	420	500	Consolidated Trans-Canada	540 438
Ricinus Leduc 19-35-8	Nil	80	Consolidated Pacific Trans-Canada	140 154 163
Strachan D-3A	700	1,400	Consolidated Gulf/Amerada Trans-Canada	1,550 1,593 1,418
Waskahigan Dunvegan A	58	90	None	-
Westerose South D-3A	1,250	1,350	Trans-Canada	1,365

Brazeau River Elkton A Pool: The Board's estimate of initial marketable reserves in the Brazeau River Elkton A Pool has been increased by 30 Bcf since December 31, 1968, due to information from one new well and a re-evaluation of the reservoir volume.

<u>Brazeau River Elkton B Pool</u>: This pool was re-evaluated after the addition of one well, and the reserves have been increased by 40 Bcf. The Trans-Canada estimate is substantially larger than that of the Board. The difference between these estimates is due largely to a variance in opinion concerning the shape and thus the volume of the reservoir.

<u>Greencourt Pekisko A Pool</u>: The addition of two wells on the east side of this pool has resulted in an increase in reserves from 62 to 85 Bcf.

<u>Harmattan East Rundle Pool</u>: The associated gas reserves in the Harmattan East Rundle Pool have been decreased by 100 Bcf despite modest enlargement of the pool in two areas. The decrease results from a re-evaluation of the gas interval porosity and water saturation, and from detection of a significant error in a previous calculation of the reservoir volume.

<u>Kaybob South Beaverhill Lake A Pool</u>: In its decision on an application by Chevron Standard Limited regarding gas cycling in this pool, the Board established the pool reserves to be 2,000 Bcf, effective May 1, 1969. In light of the evidence now before it, the Board has increased its reserve estimate to 2,100 Bcf. The increase in reserves since December 31, 1968, is attributable to an increase in estimated rock volume resulting from active development drilling. The reserve estimate of Consolidated is larger than that of the Board because of differences in estimates of fluid saturation, recovery and reservoir

volume. Trans-Canada's estimate is larger than the Board's because of differences in estimates of fluid saturation and recovery.

Obed D-2A Pool: One new D-2 well was added at Obed since the previous reserves estimate and with the information from the three wells a single pool isopach was prepared. The additional data thus led to a doubling of the D-2 reserves in the field.

Provost Viking A and Viking B Pools: The aggregate reserve estimate for these pools remains unchanged at 900 Bcf. The Board and Trans-Canada have both used material balance calculations to estimate reserves, but the resulting reserve estimates are significantly different. This difference is unlikely to be reconciled until additional pressure data are available.

Quirk Creek Rundle A Pool: The Board's evaluation of new data from this pool resulted in higher estimates of porosity and gas saturation, and increased the estimated reserves to 500 Bcf. The principal differences between the estimates of the Board, Consolidated and Trans-Canada are in recovery and reservoir volume.

Ricinus Leduc 19-35-8: The reserves of this new single well reservoir have been established by the Board at 80 Bcf. The difference between the estimates of the Board and others results principally from difference in the area assigned to the pool.

Strachan D-3A Pool: Development drilling in this high-relief

reservoir has resulted in a doubling of the reserves to 1,400 Bcf since the 1968 year-end. The main differences amongst the various reserves estimates are in the pore volume and recovery estimates.

Waskahigan Dunvegan A Pool: A reassessment of the extent of this pool resulted in the inclusion in the isopach of three wells for which individual reserves assignments were made in the past. The Board's estimate of the reserves is now 90 Bcf, some 32 Bcf greater than the previous total of the reserves of the main pool and the three wells.

Westerose South D-3A Pool: A new development well in the southern part of this pool encountered an unexpectedly large thickness of gas pay, increasing the pool average pay thickness by more than 15 per cent. Partially offsetting this is an increase in the Board's estimate of reservoir loss. The net effect of these changes on the pool reserves is an increase of 100 Bcf to 1,350 Bcf.

The Board's estimates of established reserves of gas tabulated by fields and areas are presented in Table A-1. Within each field or area, pools designated by Board orders and having initial marketable reserves of 10 billion cubic feet or greater are shown separately. The reserves of the remaining pools in a field or area are grouped by formation. The table does not show separately fields or areas where the Board's estimate of initial marketable reserves is less than 10 billion cubic feet unless the reserve is supplying a market. In addition, the table does not show reserves by field, area or formation where the data

used in calculating the reserves are confidential. In exception to this rule, the reserves of four confidential pools which were considered at the hearing or in other recent submissions to the Board, namely Bassano, Obed, Ricinus and Whiskey, are included in Table A-1 but detailed reservoir data are not tabulated for these pools.

The sum of the reserves in non-producing fields or areas having an initial marketable reserve of less than 10 billion cubic feet, and the sum of the reserves in confidential fields, areas, or zones are shown at the end of the table. These reserves are also included in the provincial total.

TABLE A-1 ESTABLISHED RESERVES OF GAS IN THE PROVINCE

*** 1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
ACHESON									
VIKING	5	0.75	0.05	4	2	2	1020	2	
BLAIRMORE	5	0.80	0.05	4	1	3	1040	3	
BLAIRMORE ASSOC	27	0.85	0.10	20**					
BLAIRMORE SOLN	7	0.65	0.55	2**	5**	17	1050	18	
D-3 A SOLN	76	0.70	0.55	26	7	19	1070*	20	
ACHESON EAST									
BLAIRMORE	2	0.85	0.10	2		2	1050	2	
BLAIRMORE SOLN	10	0.65	0.45	4		4	1050	4	
ADEN									
BOW ISLAND	5	0.85	0.05	4		4	1000	4	
BASAL COLORADO	7	0.85	0.05	6	2	4	1000	4	
BLAIRMORE	1	0.75	0.05	1		1	1020	1	
SUNBURST-SWIFT	2	0.90	0.05	2	1	1	1040	1	
MISSISSIPPIAN	13	0.90	0.10	10	8	2	1040	2	
ALDERSON									
MILK RIVER A	46	0.50	0.05	22	5	17	960	16	6460
MILK RIVER (OTHER)	5	0.70	0.05	3	1	2	960	2	
2WS A	500	0.70	0.05	330	12	318	960	305	321500
BOW ISLAND	25	0.80	0.05	20		20	1000	20	
BASAL COLORADO	13	0.85	0.05	10		10	1030	10	
ALEXANDER									
BASAL QUARTZ A	140	0.85	0.03	120	110	10	1060*	11	
MANNVILLE (OTHER)	6	0.40	0.05	2	2	□ 1	1060*	□ 1	
ALEXIS									
MANNVILLE	8	0.85	0.05	7		7	1040	7	
BANFF	11	0.85	0.15	9		9	1060	10	
ALIX									
BLAIRMORE	10	0.90	0.05	8		8	1090*	9	
D-2 ASSOC	5	0.85	0.35	3		3	1130*	3	
D-2 SOLN	6	0.65	0.65	1		1	1130*	1	
AMBER									
SLAVE POINT	3	0.90	0.15	2		2	1100*	2	
SULPHUR POINT	2	0.90	0.20	1		1	1100*	1	
MUSKEG	6	0.90	0.25	4		4	1120*	4	
KEG RIVER ASSOC	12	0.90	0.10	8		8	1200*	10	
ANTE CREEK									
PEACE RIVER	11	0.85	0.05	8		8	1100	9	
GETHING 36-67-24	13	0.85	0.05	11		11	1100	12	500
GETHING	13	0.85	0.05	10		10	1100	11	
TRIASSIC	5	0.85	0.05	4		4	1140	5	
ANTELOPE									
VIKING A	13	0.80	0.05	10	1	9	1020	9	4620
BANFF	17	0.80	0.05	13	5	8	1020	8	
ATHABASCA									
GRAND RAPIDS	6	0.85	0.05	5	2	3	1000	3	
WABAMUN	4	0.90	0.05	3		3	980	3	
ATHABASCA EAST									
MANNVILLE	1	0.80	0.05	1		1	1090	1	

□ MEANS LESS THAN
* MEASURED HIGHER HEATING VALUE

** INCLUDES ASSOCIATED GAS PRODUCTION
*** DEFINITIONS OF COLUMN HEADINGS APPEAR IN APPENDIX 1

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1966 NUL	2
									1967 NUL	3
									1967 NUL	4
									1966 NUL	5
										6
							5080	1950	1966 NUL	7
										8
										9
									1967	10
									1968 NUL	11
										12
										13
									1968 CMG	14
									1968 CMG	15
									1966	16
									1968 CMG	17
										18
									1961 CMG	19
										20
										21
52	0.20	0.50	420	55	0.94	0.58	970	1941	1968 LOCAL UTILITY	22
									1968 LOCAL UTILITY	23
5	0.20	0.40	830	80	0.90	0.58	1970	1956	1967 TCPL	24
									1964 TCPL	25
										26
									1965 LOCAL UTILITY	27
										28
										29
		GIP BASED ON MATERIAL BALANCE					3830	1954	1967 NORTH CANADIAN OILS	30
									AND CALGARY POWER	31
									1961	32
										33
										34
									1968	35
									1968	36
										37
										38
									1962	39
									1969	40
									1968	41
										42
										43
									1968 CONSIDERED BEYOND	44
									1968 ECONOMIC REACH	45
									1968	46
									1968	47
										48
										49
									1964	50
35	0.15	0.30	2200	125	0.83	0.62	5670	1961	1967	51
									1967	52
									1967	53
										54
										55
8	0.22	0.50	950	80	0.88	0.59	2360	1957	1967 TCPL	56
									1967 TCPL	57
										58
										59
									1957 LOCAL UTILITY	60
									1957	61
										62
										63
									1957	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
ATHABASCA EAST (CONTINUED)									
D-1	4	0.60	0.05	2	1	1	1000	1	
ATIM									
VIKING	2	0.80	0.05	1		1	1000	1	
MANNVILLE	2	0.85	0.05	2	1	1	1070*	1	
ATLEE-BUFFALO									
VIKING A	61	0.75	0.05	43	12	31	970	30	31910
VIKING B	29	0.75	0.05	21	1	20	970	19	17310
VIKING (OTHER)	4	0.75	0.05	3		3	970	3	
BASAL COLORADO	6	0.80	0.05	5		5	1020	5	
BASAL MANNVILLE A	29	0.80	0.05	22		22	960	21	9550
BASAL MANNVILLE B	17	0.80	0.05	13		13	960	12	4990
MANNVILLE (OTHER)	6	0.85	0.05	5		5	960	5	
BANTRY									
MILK RIVER A	46	0.80	0.05	35	1	34	960	33	18400
2WS	1	0.80	0.05	1		1	970	1	
VIKING	25	0.80	0.05	19		19	970	18	
BASAL COLORADO	3	0.80	0.05	3	1	2	970	2	
MANNVILLE	12	0.85	0.05	9		9	1030	9	
MANNVILLE A ASSOC	27	0.85	0.10	21		21	1060*	22	5040
MANN ASSOC (OTHER)	26	0.85	0.05	21		21	1060*	22	
MANNVILLE A SOLN	50	0.70	0.35	23		23	1060*	24	
BAPTISTE									
MANNVILLE	6	0.80	0.05	5		5	970	5	
WABAMUN A	15	0.80	0.05	11		11	980	11	3840
BASHAW									
VIKING	1	0.75	0.05	1		1	970	1	
MANNVILLE	13	0.90	0.05	11		11	1000	11	
MANNVILLE ASSOC	12	0.80	0.05	9		9	1030*	9	
D-3 A ASSOC	16	0.80	0.15	11		11	1100*	12	2740
D-3 ASSOC (OTHER)	2	0.80	0.15	1		1	1100*	1	
BASSANO									
BOW ISLAND	2	0.85	0.05	2		2	1010*	2	
BASAL COLORADO	6	0.80	0.05	5		5	1010*	5	
MANNVILLE C	15	0.85	0.05	12		12	1020*	12	
MANNVILLE	8	0.85	0.05	7		7	1020*	7	
BEAVER CROSSING									
COLONY	1	0.70	0.05	1		1	1000	1	
BHL LK-FT SASK									
VIKING (MAIN)	610	0.85	0.05	490	143	347	1010	350	
VIKING (OTHER)	37	0.85	0.05	30		30	1010	30	
MANNVILLE	4	0.85	0.05	3		3	1010	3	
BELLIS									
MANNVILLE	7	0.75	0.05	5		5	1015	5	
NISKU A	43	0.85	0.05	35		35	1000	35	14750
NISKU (OTHER)	1	0.70	0.05	1		1	1000	1	
BELLOY									
NOTIKEWIN	9	0.80	0.05	7		7	980	7	
GETHING A	32	0.80	0.05	24		24	980	24	12350
GETHING B	31	0.90	0.05	27		27	980	26	6170
DEBOLT A	23	0.90	0.05	20		20	1120	22	1100

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11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	Line
									1968 LOCAL UTILITY	2
									1957	5
									1963 CIGOL	6
5	0.25	0.50	990	80	0.88	0.60	2600	1951	1967 TCPL	9
4	0.25	0.50	1010	80	0.87	0.60	2320	1954	1967 TCPL	10
									1967	11
									1967	12
7	0.19	0.50	1410	90	0.85	0.59	3220	1953	1967 TCPL	14
8	0.19	0.50	1430	90	0.85	0.59	3290	1954	1967	15
									1968	16
15	0.15	0.35	400	55	0.94	0.57	960	1940	1961 LOCAL UTILITY	19
									1967	20
									1965	21
									1964 CWNG	22
									1961	24
5	0.27	0.30	1560	85	0.79	0.73	3210	1948	1969	25
									1968	26
							3250	1948	1969	27
									1968 CONSIDERED BEYOND	30
23	0.15	0.30	510	70	0.93	0.57	1940	1959	1968 ECONOMIC REACH	31
									1963	34
									1966	35
									1966	36
17	0.05	0.15	2330	140	0.85	0.78	5760	1951	1966	37
									1966	39
									1967	42
									1968	43
									1969	44
									1968	45
									1963 LOCAL UTILITY	48
		GIP BASED ON MATERIAL BALANCE					2590	1946	1966 NUL AND CIGOL	51
									1966	52
									1966	53
									1966	56
23	0.09	0.20	560	80	0.93	0.57	2100	1965	1966	57
									1966	58
									1961	61
8	0.14	0.40	1260	110	0.88	0.56	2990	1951	1961	62
14	0.14	0.40	1330	110	0.87	0.57	3100	1951	1961	63
39	0.10	0.20	1970	95	0.79	0.63	4700	1951	1961	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
BENJAMIN CREEK									
RUNDLE 33-28-7	100	0.85	0.20	70		70	1070	75	2270
BERLAND RIVER									
LEDUC A	440	0.90	0.25	300		300	990	297	1100
BERLAND RIVER WEST									
WABAMUN 10-58-25	24	0.90	0.30	15		15	1020	15	1100
BERRY									
VIKING	1	0.85	0.05	1		1	1020	1	
MANNVILLE	8	0.85	0.05	7		7	1030	7	
BIG BEND									
WABISKAW 31-68-1	12	0.90	0.05	10		10	990	10	1100
MCMURRAY A	26	0.80	0.05	19		19	990	19	3920
MANNVILLE (OTHER)	33	0.75	0.05	24		24	990	24	
WABAMUN	20	0.80	0.05	15		15	1000	15	
BIGORAY									
PASKAPOO	2	0.60	0.05	1		1	1000	1	
BLAIRMORE	18	0.85	0.05	14		14	1080	15	
RUNDLE	20	0.85	0.10	15		15	1080	16	
BIGSTONE									
DUNVEGAN A	53	0.90	0.05	45		45	1140	51	6390
GETHING A	13	0.90	0.05	11		11	1070	12	1100
GETHING (OTHER)	11	0.90	0.05	9		9	1100	10	
WABAMUN	11	0.85	0.40	5		5	1050	5	
D-3 A	390	0.85	0.25	250	10	240	990*	238	7090
BINDLOSS									
VIKING A	420	0.75	0.05	300	118	182	980	178	57050
VIKING B	32	0.70	0.05	21	2	19	980	19	6110
VIKING (OTHER)	6	0.75	0.05	5		5	980	5	
BASAL MANNVILLE A	26	0.90	0.05	23		23	990	23	5310
BANFF	3	0.85	0.05	2		2	1000	2	
BITTERN LAKE									
VIKING	11	0.80	0.05	8		8	1020	8	
GLAUCONITIC A	38	0.85	0.05	30	7	23	1070	25	3530
GLAUCONITIC B	21	0.85	0.05	17	2	15	1070	16	1210
ELLERSLIE A	14	0.85	0.05	12		12	1070	13	2370
MANNVILLE	44	0.85	0.05	35		35	1070	37	
BLACK									
SLAVE POINT	18	0.90	0.15	13		13	1100	14	
SULPHUR POINT ASSOC	1	0.85	0.15	1		1	1100	1	
MUSKEG	1	0.85	0.10	1		1	1100	1	
KEG RIVER	5	0.85	0.15	3		3	1150	3	
KEG RIVER ASSOC	4	0.85	0.15	3		3	1200	4	
BLACK BUTTE									
2WS	2	0.80	0.05	2		2	960	2	
BOW ISLAND A	21	0.85	0.05	17	3	14	980	14	3300
BASAL COLORADO A	15	0.85	0.05	12	4	8	1000	8	2840
BSL COLORADO (OTHER)	10	0.85	0.05	8	5	3	1000	3	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
112	0.05	0.20	3910	230	0.93	0.68	10600	1961	1966
562	0.08	0.20	5340	250	1.00	0.70	12290	1958	1959
71	0.04	0.20	4800	260	0.98	0.70	12320	1958	1959 CONSIDERED BEYOND
									ECONOMIC REACH
									1969 TCPL
									1967 TCPL
29	0.20	0.30	800	80	0.86	0.59	2430	1957	1957
17	0.20	0.35	900	85	0.88	0.60	2710	1953	1965
									1968
									1968
									1959
									1960
									1959
12	0.15	0.45	2600	145	0.79	0.69	6440	1959	1966
20	0.14	0.30	2500	215	0.89	0.66	7780	1960	1961
									1961
									1964
86	0.07	0.15	4800	240	0.97	0.69	11080	1960	1964 TCPL
14	0.29	0.45	990	80	0.88	0.59	2260	1952	1967 TCPL
10	0.29	0.45	1000	80	0.88	0.59	2530	1957	1967 TCPL
									1967
7	0.23	0.40	1460	85	0.85	0.59	2770	1954	1967
									1967
									1967
17	0.25	0.40	1310	115	0.86	0.64	4010	1956	1967 CIGOL, PLAINS WEST
29	0.24	0.40	1370	115	0.85	0.64	4180	1947	1967 ERN GAS & ELEC AND
									NUL
11	0.19	0.35	1350	115	0.83	0.68	4140	1952	1967
									1967 CIGOL
									1967 CONSIDERED BEYOND
									1967 ECONOMIC REACH
									1967
									1967
									1967
									1961
25	0.20	0.35	660	75	0.92	0.56	2200	1944	1963 CMG
15	0.20	0.40	930	80	0.89	0.58	2540	1944	1968 CMG
									1968 CMG

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
BLACK BUTTE (CONTINUED)									
SUNBURST-SWIFT A	18	0.90	0.05	15	9	6	1000	6	2040
SAWTOOTH A	28	0.80	0.05	21	17	4	1000	4	
MANNVILLE (OTHER)	7	0.85	0.05	5		5	1030	5	
RUNDLE A	16	0.80	0.05	12	5	7	1020	7	2750
BLACK DIAMOND									
RUNDLE A	24	0.85	0.15	17		17	1100	19	500
BLUERIDGE									
MANNVILLE	3	0.80	0.05	2		2	1100	2	
JURASSIC A	14	0.90	0.05	12		12	1100	13	500
JURASSIC (OTHER)	8	0.80	0.10	5		5	1100	6	
PEKISKO	2	0.75	0.05	2		2	1130	2	
PEKISKO ASSOC	7	0.80	0.10	5		5	1130	6	
BOLLOQUE LAKE									
VIKING	2	0.80	0.05	1		1	1060	1	
MANNVILLE	14	0.80	0.05	10		10	990	10	
BONNIE GLEN									
CARDIUM SOLN	2	0.65	0.10	1		1	1040*	1	
VIKING	2	0.85	0.10	1		1	1050	1	
MANNVILLE	5	0.85	0.10	4	3	1	1100*	1	
WABAMUN	1	0.85	0.10	1		1	1100*	1	
GRAMINIA	1	0.85	0.10	1		1	1100*	1	
D-3	14	0.70	0.15	9	7	2	1100*	2	
D-3 A ASSOC	430	0.85	0.15	310		310	1220*	378	2990
D-3 A SOLN	540	0.70	0.25	280	56	224	1220*	273	
BONNYVILLE									
MANNVILLE	4	0.80	0.05	3	3	□ 1	980	□ 1	
MANNVILLE ASSOC	1	0.80	0.05	1		1	980	1	
BOUNDARY LAKE SOUTH									
CADOMIN	11	0.80	0.10	8		8	1060	8	
TRIASSIC	4	0.85	0.10	4	1	3	1050	3	
KISKATINAW D	37	0.85	0.05	29	11	18	1080	19	
KISKATINAW E	19	0.85	0.10	15		15	1080	16	1100
KISKATINAW (OTHER)	4	0.85	0.05	3	2	1	1080	1	
GOLATA A	13	0.85	0.05	11	8	3	1080	3	1000
GOLATA B	16	0.85	0.05	13	7	6	1080	6	1000
BOW ISLAND									
BOW ISLAND	48	0.90	0.05	40	14	26	1030	27	
BOYLE									
MANNVILLE	6	0.80	0.05	5		5	1000	5	
DETRITAL	2	0.85	0.05	1		1	1000	1	
NISKU	9	0.85	0.05	8		8	990	8	
BRAEBURN									
CADOMIN	4	0.80	0.05	3	1	2	1060*	2	
BALDONNEL A	29	0.80	0.10	21	5	16	1090*	17	4890
BELLOY A	55	0.80	0.05	42	3	39	1030*	40	3560
BRAZEAU RIVER									
ELKTON A	670	0.80	0.10	480		480	1050*	504	41180
ELKTON B	250	0.80	0.10	180		180	1040*	187	16230
SHUNDA A	110	0.75	0.10	74		74	1080*	80	24370

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	Line
19	0.20	0.30	1030	85	0.87	0.57	2960	1944	1963 CMG	2
		GIP BASED ON MATERIAL BALANCE					3200	1944	1967 CMG	3
									1963 CMG	4
18	0.10	0.20	1200	90	0.87	0.58	3280	1944	1968 CMG	5
59	0.10	0.15	3630	195	0.87	0.74	9020	1967	1967	8
									1964	11
26	0.28	0.30	1800	150	0.85	0.66	5500	1957	1966	12
									1968	13
									1968	14
									1969	16
									1966	19
									1967	20
									1965	23
									1963	24
									1964 NUL	25
									1967	26
									1967	28
									1967 NUL	29
216	0.09	0.10	2440	140	0.79	0.70	6700	1952	1966	30
							7000	1952	1966 NUL	31
									1964 LOCAL UTILITY	34
									1963	35
									1964	38
									1968	39
		GIP BASED ON MATERIAL BALANCE					6210	1964	1969 WESTCOAST	40
22	0.13	0.10	2360	145	0.86	0.60	6130	1965	1969 WESTCOAST	41
									1966 WESTCOAST	43
17	0.14	0.20	2370	145	0.86	0.59	6100	1958	1969 WESTCOAST	44
20	0.14	0.20	2370	145	0.86	0.59	6100	1964	1969 WESTCOAST	45
		RESERVE BASED ON PRODUCTION & INJECTION DATA					1920	1909	1953 CWNG STORAGE	48
									RESERVOIR	49
									1966	52
									1966	53
									1966	54
									1966 WESTCOAST	57
8	0.16	0.30	2150	145	0.86	0.61	5680	1954	1968 WESTCOAST	58
35	0.11	0.50	2970	180	0.90	0.58	7280	1954	1968 WESTCOAST	59
17	0.11	0.10	3860	215	0.94	0.64	10150	1959	1969	62
19	0.11	0.20	3870	230	0.95	0.68	9870	1965	1969	63
9	0.08	0.30	3910	205	0.94	0.65	10200	1965	1968	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
BROOKS									
MILK RIVER	9	0.80	0.05	7	4	3	990	3	
BROWN CREEK									
RUNDLE 20-44-17	59	0.80	0.15	40		40	970	39	2000
BRUCE									
VIKING	25	0.80	0.05	19		19	1000	19	
MANNVILLE	9	0.80	0.05	7		7	1020	7	
BURNT TIMBER									
RUNDLE A	370	0.85	0.20	250		250	1030	258	12160
CALAIS									
GETHING	14	0.85	0.05	11		11	1000	11	
CADOMIN	12	0.85	0.05	10		10	1000	10	
CALLING LAKE									
MANNVILLE	2	0.85	0.05	2		2	1000	2	
D-2 A	49	0.75	0.05	35		35	1000	35	24810
CAMPBELL-NAMAO									
BLAIRMORE	4	0.85	0.05	3		3	1020	3	
BLAIRMORE E ASSOC	31	0.80	0.05	23**					1740
BLAIR ASSOC (OTHER)	11	0.80	0.05	8**					
BLAIRMORE SOLN	8	0.60	0.05	4**	20**	15	1020*	15	
CARBON									
BASAL COLORADO	4	0.85	0.05	3		3	1020	3	
GLAUCONITIC	160	0.85	0.05	130	29	101	1120	113	11800
MANNVILLE (OTHER)	4	0.85	0.05	3		3	1100	3	
RUNDLE	4	0.85	0.05	3		3	1110	3	
CAROLINE									
VIKING	2	0.80	0.05	1		1	1040*	1	
VIKING A ASSOC	160	0.80	0.05	120	5	115	1040*	120	40600
BASAL MANNVILLE B	15	0.85	0.10	12	1	11	1070	12	500
BASAL MANNVILLE C	16	0.85	0.10	12		12	1070	13	500
MANNVILLE (OTHER)	17	0.85	0.05	13		13	1040*	14	
ELKTON D	14	0.85	0.10	11		11	1020*	11	500
ELKTON (OTHER)	12	0.85	0.15	9		9	1020*	9	
CARSON CREEK									
BEAVERHILL LAKE A	210	0.85	0.15	150	10	140	1080*	151	15840
BEAVERHILL LAKE B	110	0.85	0.15	80	-16	96	1080*	104	6980
CARSON CREEK NORTH									
BHL LK A ASSOC	26	0.85	0.15	19		19	1100*	21	2880
BHL LK ASSOC (OTHER)	7	0.85	0.15	5		5	1100*	6	
BHL LK A SOLN	110	0.45	0.20	38	4	34	1100*	37	
BHL LK B SOLN	330	0.40	0.20	110	9	101	1100*	111	
CARSTAIRS									
BLAIRMORE	16	0.85	0.15	11		11	1100	12	
ELKTON A	1140	0.90	0.15	870	261	609	1070*	652	
ELKTON ASSOC	6	0.85	0.15	5		5	1070*	5	
CASTOR									
VIKING A	33	0.80	0.05	25		25	1040	26	20320

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	Line
									1961 LOCAL UTILITY	2
89	0.04	0.20	4550	115	0.98	0.64	10840	1960	1964 CONSIDERED BEYOND	5
									ECONOMIC REACH	6
									1967	9
									1967	10
61	0.06	0.15	3800	105	0.91	0.72	10900	1959	1966	13
									1960 LOCAL UTILITY	16
									1964	17
									1967 GREAT CANADIAN OIL	20
									SANDS LIMITED	21
25	0.13	0.45	360	70	0.95	0.56	1550	1964	1967 GREAT CANADIAN OIL	22
									SANDS LIMITED	23
									1964	26
30	0.19	0.20	1220	115	0.85	0.67	3620	1951	1969 CIGOL	27
									1969 CIGOL	28
									1964 CIGOL	29
									1964	32
22	0.20	0.35	1480	120	0.83	0.68	4750	1955	1966 CWNG	33
									1964	34
									1965	35
									1967	38
7	0.11	0.25	2500	165	0.83	0.67	8070	1957	1967 TCPL	39
26	0.15	0.30	4260	185	0.92	0.78	9460	1958	1964 A&S	40
27	0.15	0.30	4040	180	0.89	0.78	8900	1964	1965	41
									1965 TCPL	43
29	0.12	0.20	3600	195	0.86	0.83	9170	1960	1965 A&S	44
									1965 A&S	45
20	0.08	0.20	3790	200	0.85	0.97	8550	1961	1964 POOLS BEING CYCLED	48
24	0.08	0.20	3790	200	0.85	0.97	8610	1957	1964 AND GAS SOLD TO NUL	49
									AND A&S	50
10	0.09	0.90	3740	185	0.84	0.79	8580	1958	1969	53
							8700	1958	1969	54
							8630	1959	1965 INJ INTO CARSON CRK	55
							8740	1958	1965 INJ INTO CARSON CRK	56
									1967	59
		GIP BASED ON MATERIAL BALANCE					8100	1958	1967 TCPL	60
									1967	61
6	0.21	0.55	860	90	0.89	0.61	3160	1949	1969	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
1	2	3	4	5	6	7	8	9	10
CASTOR (CONTINUED)									
MANNVILLE	4	0.85	0.05	3		3	1090	3	
CESSFORD									
VIKING H	16	0.75	0.03	11		11	1020*	11	6460
VIKING I	14	0.75	0.03	10		10	1020*	10	1100
VIKING (OTHER)	78	0.65	0.03	49	8	41	1060*	43	
BASAL COLORADO E	120	0.80	0.04	90	41	49	1030*	50	24430
BSL COLORADO (OTHER)	55	0.65	0.04	34	5	29	1030*	30	
BSL COLO A ASSOC	890	0.85	0.04	730	339	391	1030*	403	135000
BSL COLORADO A SOLN	20	0.65	0.21	10		10	1030*	10	
GLAUCONITIC A	19	0.75	0.05	13		13	1080*	14	8410
GLAUCONITIC B	15	0.75	0.05	11	1	10	1080*	11	5810
MANNVILLE A	59	0.80	0.04	45	15	30	1000*	30	13580
MANNVILLE F	23	0.85	0.04	19	3	16	1000*	16	3670
MANNVILLE G	40	0.85	0.04	33	21	12	1000*	12	5760
MANNVILLE H	71	0.85	0.04	58	24	34	1000*	34	7010
MANNVILLE I	22	0.75	0.04	16	5	11	1000*	11	5470
MANNVILLE J	32	0.85	0.04	26	14	12	1000*	12	4870
MANNVILLE K	17	0.75	0.04	12	1	11	1000*	11	3300
MANNVILLE (OTHER)	61	0.85	0.04	49	16	33	1030*	34	
MANNVILLE C ASSOC	19	0.85	0.04	16		16	1030*	16	3930
MANN ASSOC (OTHER)	2	0.85	0.04	1		1	1030*	1	
MANNVILLE SOLN	12	0.65	0.17	7	4	3	1030*	3	
CHAMBERS									
BLAIRMORE	6	0.85	0.10	4		4	1030	4	
ELKTON	13	0.85	0.15	9		9	1080	10	
CHARLOTTE LAKE									
MANNVILLE	3	0.75	0.05	2		2	1000	2	
CHESTERMERE									
RUNDLE A	35	0.85	0.15	25		25	1100	28	1100
CHIGWELL									
MANNVILLE A	46	0.85	0.10	35	13	22	1110	24	
MANNVILLE (OTHER)	13	0.75	0.10	9	1	8	1110	9	
CHINOOK RIDGE									
PADDY	13	0.80	0.10	9		9	1020	9	
CADOTTE 12-65-13	32	0.80	0.10	23		23	1020	23	1100
NOTIKEWIN 12-65-13	20	0.80	0.10	15		15	1020	15	500
CLIVE									
VIKING	4	0.80	0.05	3		3	990	3	
MANNVILLE	5	0.85	0.05	4		4	1020	4	
D-2 A ASSOC	39	0.85	0.30	23		23	1050*	24	4240
D-2 ASSOC (OTHER)	1	0.85	0.30	1		1	1050*	1	
D-2 SOLN	38	0.40	0.55	7		7	1050*	7	
D-3 A ASSOC	33	0.75	0.30	18		18	1050*	19	3950
D-3 A SOLN	70	0.40	0.60	11		11	1050*	12	
COLD LAKE									
MANNVILLE	8	0.70	0.05	6	4	2	1000	2	
COMREY									
2WS	5	0.80	0.05	4		4	940	4	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1963 LOCAL UTILITY
6	0.21	0.45	1110	75	0.86	0.59	2630	1953	1968
15	0.21	0.45	1100	80	0.86	0.59	2730	1953	1968
									1968 TCPL
8	0.24	0.40	1260	85	0.84	0.61	2970	1950	1968 TCPL
									1968 TCPL
10	0.27	0.40	1260	80	0.84	0.61	2860	1950	1968 TCPL
							2870	1950	1968
6	0.17	0.50	1370	100	0.82	0.65	3850	1960	1968 TCPL
6	0.17	0.50	1370	95	0.82	0.65	3570	1962	1968
13	0.16	0.55	1410	100	0.82	0.66	3870	1959	1968 TCPL
10	0.24	0.45	1420	90	0.81	0.65	3290	1951	1968 TCPL
13	0.21	0.50	1420	90	0.81	0.65	3390	1950	1968 TCPL
14	0.25	0.45	1440	85	0.80	0.65	3070	1954	1968 TCPL
7	0.27	0.50	1420	90	0.81	0.65	3340	1951	1968 TCPL
10	0.23	0.45	1540	90	0.80	0.65	3400	1958	1968 TCPL
8	0.27	0.50	1420	90	0.81	0.65	3255	1952	1968 TCPL
									1968 TCPL
6	0.24	0.35	1400	90	0.81	0.65	3320	1951	1968 TCPL
									1968
									1968
									1967
									1967
									1967 CANADIAN FORCES BASE
									AT COLD LAKE
42	0.10	0.15	2790	155	0.80	0.76	6810	1968	1968
		GIP BASED ON MATERIAL BALANCE					5160	1952	1968 TCPL
									1968 TCPL
									1961 CONSIDERED BEYOND
23	0.20	0.30	3300	230	0.85	0.80	9200	1956	1961 ECONOMIC REACH
32	0.20	0.30	3400	235	0.86	0.80	9460	1956	1961
									1966
									1966
20	0.06	0.15	2480	150	0.73	0.75	6040	1951	1967
									1968
									1968
20	0.06	0.15	2550	150	0.73	0.81	6140	1952	1967
							6150	1952	1968
									1966 LOCAL UTILITY
									1960

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1 POOL OR ZONE	2 INITIAL GAS IN PLACE BCF	3 POOL RECOVERY FRACTION	4 SURFACE LOSS FRACTION	5 INITIAL MARKETABLE GAS BCF	6 MARKETABLE GAS PRODUCED MAY 31/69 BCF	7 REMAINING MARKETABLE GAS MAY 31/69 BCF	8 GROSS HEATING VALUE BTU/CU.FT.	9 REMAINING MARKETABLE GAS AT 1000 BTU BCF	10 AREA ACRES
COMREY (CONTINUED)									
BOW ISLAND	34	0.75	0.05	24	17	7	940	7	6980
BOW ISLAND (OTHER)	1	0.80	0.05	1		1	940	1	
UPPER MANNVILLE A	16	0.90	0.05	14		14	1000	14	1100
SAWTOOTH	1	0.80	0.05	1		1	1000	1	
CONNORSVILLE									
VIKING	8	0.80	0.05	6	2	4	1000	4	
LOWER MANNVILLE A	52	0.85	0.05	42	3	39	1100	43	10110
MANNVILLE (OTHER)	10	0.85	0.05	8	1	7	1100	8	
COUNTESS									
BOW ISLAND A	34	0.80	0.05	26	5	21	1010*	21	14490
BOW ISLAND C	17	0.80	0.05	13	1	12	1010*	12	6080
BOW ISLAND F	15	0.85	0.05	12		12	1010*	12	2230
BOW ISLAND (OTHER)	29	0.80	0.05	22	1	21	1010*	21	
BASAL COLORADO A	170	0.85	0.05	140	76	64	1010*	65	
BSL COLORADO (OTHER)	6	0.90	0.05	5		5	1010*	5	
MANNVILLE	48	0.85	0.05	38	6	32	1020*	33	
BASAL QUARTZ B ASSOC	12	0.85	0.05	10		10	1020*	10	1370
MANN ASSOC (OTHER)	5	0.85	0.05	4		4	1020*	4	
MISS ASSOC	3	0.80	0.10	2		2	1030*	2	
CRAIGEND									
PELICAN	3	0.75	0.05	2		2	1000	2	
MANNVILLE	48	0.75	0.05	34		34	1000	34	
MANNVILLE ASSOC	3	0.75	0.05	2		2	1000	2	
GROSMONT A	210	0.75	0.05	150		150	1000	150	81000
CRAIG LAKE									
VIKING	1	0.75	0.05	1		1	1000	1	
CROSSFIELD									
CARDIUM SOLN	74	0.30	0.45	12	1	11	1140*	13	
BASAL QUARTZ A	81	0.85	0.10	62	2	60	1020*	61	12160
BASAL QUARTZ (OTHER)	36	0.85	0.10	28	1	27	1020*	28	
RUNDLE A	1230	0.90	0.10	1000	185	815	1070*	872	33600
RUNDLE B	900	0.85	0.15	650	214	436	1070*	467	21220
RUNDLE D	13	0.85	0.10	10		10	1020*	10	500
WABAMUN A	2080	0.85	0.50	890	106	784	980	768	102680
CROSSFIELD EAST									
BLAIRMORE	6	0.85	0.10	5		5	1020*	5	
ELKTON A	150	0.90	0.12	120	34	86	1140*	98	
ELKTON C	32	0.85	0.10	24		24	1140*	27	1100
WABAMUN A	1590	0.85	0.55	610	13	597	970	579	55510
DIXONVILLE									
MANNVILLE	9	0.85	0.05	7		7	980	7	
TRIASSIC	8	0.90	0.05	7		7	1030	7	
LEDUC	4	0.85	0.05	3		3	1070	3	
DONALDA									
VIKING B	25	0.80	0.05	19		19	970	18	9390
VIKING C	17	0.80	0.05	13		13	970	13	7170
VIKING (OTHER)	16	0.80	0.05	12		12	970	12	
MANNVILLE	11	0.85	0.05	9		9	980	9	
DOWLING LAKE									
MANNVILLE	5	0.80	0.05	3	2	1	1030*	1	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	Line
										1
16	0.25	0.50	770	80	0.92	0.59	2480	1952	1968 CMG	2
									1960	3
33	0.21	0.35	990	80	0.88	0.57	2750	1968	1968 CMG	4
									1960	6
									1964 TCPL	9
11	0.16	0.35	1410	105	0.85	0.61	3650	1956	1965 TCPL	10
									1965 TCPL	11
6	0.23	0.50	1040	85	0.87	0.60	2890	1951	1968 TCPL	14
7	0.22	0.50	1040	85	0.87	0.60	2860	1955	1968 TCPL	15
13	0.27	0.50	1170	85	0.86	0.60	2830	1967	1968	16
									1968 TCPL	17
		GIP BASED ON MATERIAL BALANCE					3500	1951	1968 TCPL	19
									1968	20
									1964 TCPL	21
13	0.21	0.30	1470	110	0.82	0.67	4280	1958	1964	22
									1968	23
									1961	25
									1967	28
									1968	29
									1967	30
31	0.12	0.55	410	75	0.94	0.58	1660	1961	1967	31
									1968 LOCAL UTILITY	34
							6670	1956	1966 TCPL	37
9	0.11	0.30	2890	150	0.82	0.70	7330	1957	1966 WESTCOAST AND TCPL	38
									1966 TCPL	39
39	0.12	0.15	3320	180	0.86	0.79	8410	1956	1964 A&S AND TCPL	40
71	0.08	0.15	3040	165	0.88	0.70	7440	1957	1967 WESTCOAST AND TCPL	42
44	0.08	0.20	3310	180	0.88	0.71	8200	1951	1964	43
34	0.06	0.15	3630	165	0.71	0.90	8500	1954	1967 WESTCOAST AND TCPL	44
									1968	47
		GIP BASED ON MATERIAL BALANCE					7490	1960	1968 TCPL	48
48	0.09	0.20	2780	170	0.82	0.74	7590	1967	1968	49
51	0.05	0.20	3630	180	0.72	0.91	9000	1960	1968 TCPL	50
									1962 CONSIDERED BEYOND	53
									1962 ECONOMIC REACH	54
									1962	55
6	0.23	0.35	920	100	0.90	0.60	3280	1960	1969 CONSIDERED BEYOND	58
6	0.23	0.35	905	100	0.90	0.60	3420	1957	1969 ECONOMIC REACH	59
									1969	60
									1969	61
									1960 LOCAL UTILITY	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU. FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
DRUMHELLER									
VIKING	3	0.85	0.05	2		2	1080	2	
MANNVILLE F	27	0.85	0.05	21	1	20	1080	22	37440
MANNVILLE H	16	0.85	0.10	12	2	10	1080	11	2360
MANNVILLE (OTHER)	26	0.85	0.05	20		20	1080	22	
MANNVILLE ASSOC	12	0.80	0.05	9		9	1080	10	
PEKISKO	3	0.80	0.10	2		2	1080	2	
DUHAMEL									
VIKING	4	0.90	0.05	4		4	1000	4	
MANNVILLE	5	0.85	0.05	4		4	1030	4	
D-2 ASSOC	2	0.90	0.10	2		2	1100	2	
D-3 SOLN	6	0.50	0.55	1		1	1100	1	
DUNVEGAN									
CADOTTE	9	0.75	0.05	7		7	1010	7	
DEBOLT	3	0.90	0.05	3		3	1040	3	
DUVERNAY									
VIKING	4	0.80	0.05	3	2	1	1000*	1	
DYBERG									
BELLY RIVER	3	0.80	0.05	2		2	950	2	
VIKING	8	0.90	0.05	7		7	1000	7	
BSL QTZ 15-44-23	12	0.90	0.05	10		10	1020	10	1200
EAGLESHAM									
BLUESKY	5	0.85	0.05	4		4	1000	4	
CADOMIN ASSOC	7	0.85	0.05	5		5	1060	5	
DEBOLT A	17	0.85	0.05	14		14	1110	16	2040
DEBOLT B	19	0.85	0.05	15		15	1110	17	1100
DEBOLT C	26	0.85	0.05	21		21	1110	23	1100
EDSON									
GETHING A	210	0.85	0.10	160		160	1050	168	11310
ELKTON A	2340	0.90	0.10	1900	199	1701	1030*	1752	121500
ELKTON 26-51-19	22	0.85	0.10	17		17	1030*	18	1100
ELKTON (OTHER)	6	0.85	0.10	5		5	1030*	5	
SHUNDA	12	0.80	0.15	8		8	1030*	8	
EDWAND									
MANNVILLE	4	0.80	0.05	3		3	1000	3	
ELK POINT									
MANNVILLE	3	0.80	0.05	2	1	1	990*	1	
ELLERSLIE									
BLAIRMORE ASSOC	2	0.75	0.15	1		1	1000	1	
ENCHANT									
MILK RIVER	5	0.75	0.05	3		3	1000*	3	
BOW ISLAND A	15	0.75	0.05	11		11	1000*	11	28780
BOW ISLAND (OTHER)	16	0.85	0.05	12	3	9	1000*	9	
BASAL COLORADO	1	0.75	0.05	1		1	1000*	1	
UPPER MANNVILLE A	13	0.85	0.05	11	3	8	1000*	8	4010
MANNVILLE	10	0.85	0.10	8		8	1000*	8	
JURASSIC	2	0.75	0.10	2		2	1000*	2	
RUNDLE	5	0.85	0.10	4	2	2	1000*	2	

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
									1967	2
9	0.20	0.25	1430	120	0.82	0.68	4220	1950	1968 TCPL	3
15	0.16	0.45	1450	125	0.84	0.66	4370	1961	1968 TCPL	4
									1966	5
									1966	7
									1963 TCPL	8
									1965	11
									1965	12
									1957	13
									1966	14
									1963 CONSIDERED BEYOND	17
									1963 ECONOMIC REACH	18
									1961 WESTERN MINERALS AND	21
									LOCAL UTILITY	22
									1960 CONSIDERED BEYOND	25
									1960 ECONOMIC REACH	26
17	0.18	0.30	1480	130	0.84	0.62	4620	1954	1960	27
									1965	30
									1965	31
11	0.18	0.25	1870	135	0.85	0.64	4480	1952	1966	32
17	0.20	0.20	1980	125	0.83	0.64	4700	1959	1965	33
23	0.20	0.20	2000	125	0.81	0.65	4700	1959	1965	35
27	0.10	0.25	3360	180	0.88	0.68	8400	1963	1968 TCPL	38
22	0.11	0.10	3880	225	0.94	0.63	9380	1962	1967 TCPL	39
31	0.08	0.10	3990	210	0.94	0.63	10120	1964	1966	40
									1966	41
									1966 TCPL	43
									1966 LOCAL UTILITY	46
									1964 LOCAL UTILITY	49
									1966 EDMONTON LIQUID GAS	52
									1964	55
2	0.15	0.30	950	80	0.89	0.59	2470	1960	1967 TCPL	56
									1967 TCPL	57
									1962	58
5	0.20	0.35	1580	90	0.81	0.66	3300	1953	1968 TCPL	60
									1961 TCPL	61
									1961	62
									1966 TCPL	63

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1 POOL OR ZONE	2 INITIAL GAS IN PLACE BCF	3 POOL RECOVERY FRACTION	4 SURFACE LOSS FRACTION	5 INITIAL MARKETABLE GAS BCF	6 MARKETABLE GAS PRODUCED MAY 31/69 BCF	7 REMAINING MARKETABLE GAS MAY 31/69 BCF	8 GROSS HEATING VALUE BTU/CU. FT.	9 REMAINING MARKETABLE GAS AT 1000 BTU BCF	10 AREA ACRES
EQUITY									
MANNVILLE	4	0.80	0.05	3		3	1130*	3	
LWR MANN A - PEK A	46	0.85	0.10	33	2	31	1130*	35	8720
ERSKINE									
VIKING	4	0.80	0.05	3		3	1040	3	
BLAIRMORE	21	0.80	0.10	15	4	11	1090	12	
D-2 SOLN	1	0.65	0.35	1		1	1100	1	
D-3	1	0.85	0.20	1		1	1070	1	
D-3 A ASSOC	29	0.90	0.20	21		21	1070	22	2510
D-3A SOLN	19	0.50	0.75	2		2	1110	2	
ESTHER									
BELLY RIVER A	21	0.75	0.05	15		15	990	15	31050
BANFF A	21	0.85	0.05	17	2	15	1000	15	1600
ETHEL LAKE									
MANNVILLE	3	0.80	0.05	2		2	1000	2	
ETZIKOM									
BOW ISLAND A	68	0.75	0.05	48	35	13	930	12	
MANNVILLE	2	0.75	0.05	1		1	1010	1	
EXCELSIOR									
VIKING	8	0.80	0.05	7	3	4	1000	4	
MANNVILLE A ASSOC	38	0.90	0.05	33		33	970	32	3270
EYREMORE									
BOW ISLAND	15	0.70	0.05	10		10	960	10	
FAIRYDELL-BON ACCORD									
VIKING A	110	0.80	0.05	88	35	53	1020	54	
VIKING (OTHER)	9	0.80	0.05	7	1	6	1020	6	
MANNVILLE	15	0.80	0.05	12	2	10	990	10	
MANNVILLE ASSOC	9	0.80	0.10	7		7	990	7	
FENN-BIG VALLEY									
VIKING	19	0.80	0.90	2	1	1	1000*	1	
D-2 A SOLN	150	0.65	0.85	15	7	8	1110*	9	
D-3 SOLN	9	0.60	0.85	1		1	1110*	1	
FERRIER									
CARDIUM	8	0.80	0.10	6		6	1000	6	
CARDIUM D ASSOC	74	0.80	0.10	53		53	1000	53	7710
CARDIUM E ASSOC	350	0.80	0.10	250		250	1000	250	13800
VIKING A SOLN	31	0.65	0.25	15	3	12	1130	14	
RUNDLE	2	0.80	0.10	2		2	1100	2	
BANFF	8	0.85	0.10	6		6	1100	7	
FIGURE LAKE									
VIKING	4	0.75	0.05	3		3	960	3	
MANNVILLE	13	0.80	0.05	10		10	1000	10	
D-2 B	13	0.85	0.05	11		11	1000	11	6700
D-2 (OTHER)	12	0.85	0.05	8		8	1000	8	
FLAT									
MANNVILLE	13	0.80	0.05	10		10	1020	10	
WABAMUN A	156	0.80	0.05	119		119	1040	124	32650

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1968 TCPL
21	0.08	0.35	1620	125	0.83	0.67	5420	1962	1967 TCPL
									1962
									1966 TCPL
									1969
									1968
33	0.06	0.20	2210	145	0.81	0.70	5300	1953	1966
									1966
3	0.31	0.35	330	55	0.95	0.58	800	1956	1964
26	0.19	0.30	1180	85	0.87	0.59	2770	1965	1966 TCPL
									1967 LOCAL EXPERIMENTAL PROJECT
		GIP BASED ON MATERIAL BALANCE					2230	1951	1967 SOUTH ALBERTA PIPE LINES
									1961
									1953 CIGOL AND PLAINS-WESTERN GAS & ELEC
24	0.20	0.35	1140	80	0.87	0.63	3450	1953	1953
									1955 CONSIDERED BEYOND ECONOMIC REACH
		GIP BASED ON MATERIAL BALANCE					2680	1950	1968 NUL
									1963 NUL
									1965 NUL
									1968
									1961 CWNG
							5290	1950	1966 CWNG
									1966
									1968
7	0.16	0.15	3170	160	0.83	0.71	6680	1965	1968
21	0.15	0.20	3140	150	0.80	0.77	6790	1965	1968
							8190	1955	1966 A&S
									1960
									1967
									1966
									1966
13	0.14	0.45	630	180	0.92	0.57	2260	1957	1966
									1966
									1968 LOCAL UTILITY
28	0.23	0.50	490	70	0.93	0.58	1870	1956	1968 TCPL

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
FOREMOST									
BOW ISLAND	31	0.85	0.05	27	8	19	950	18	10400
FORT KENT									
COLONY	6	0.75	0.05	4	2	2	980	2	
FOX CREEK									
VIKING A	97	0.75	0.05	69	1	68	1110	75	21790
NOTIKEWIN	7	0.80	0.05	5		5	1180	6	
CADOMIN	46	0.85	0.05	37		37	1160	43	
TRIASSIC	3	0.90	0.10	2		2	1160	2	
FOX CREEK WEST									
CADOMIN	15	0.85	0.05	12		12	1160	14	
GARRINGTON									
MANNVILLE	12	0.85	0.10	9		9	1010	9	
MANNVILLE ASSOC	3	0.90	0.15	2		2	1010	2	
RUNDLE	2	0.85	0.10	1		1	1020	1	
LEDUC 23-35-4	23	0.85	0.20	15		15	1020	15	500
LEDUC (OTHER)	7	0.85	0.20	5		5	1020	5	
LEDUC ASSOC 36-35-4	15	0.85	0.20	10		10	1020	10	500
GHOST PINE									
VIKING	9	0.80	0.05	7		7	1020	7	
UPPER MANNVILLE G&P	42	0.80	0.10	30	12	18	1030	19	11300
UPPER MANNVILLE Q	27	0.80	0.10	20		20	1030	21	2390
UPPER MANNVILLE U	28	0.80	0.10	20		20	1030	21	2850
LOWER MANNVILLE F	19	0.85	0.10	14	1	13	1030	13	1940
MANNVILLE (OTHER)	74	0.80	0.10	54	12	42	1030	43	
UPPER MANN W ASSOC	15	0.80	0.15	10		10	1050	11	5490
MANN ASSOC (OTHER)	23	0.75	0.15	15	1	14	1050	15	
PEKISKO B	17	0.80	0.10	12		12	1070	13	6520
RUNDLE (OTHER)	11	0.80	0.10	8	2	6	1070	6	
GILBY									
CARDIUM	2	0.85	0.10	2		2	1000	2	
VIKING ASSOC	4	0.80	0.05	3		3	1080*	3	
BASAL MANNVILLE D	33	0.80	0.15	22	5	17	1080*	18	2360
BASAL MANNVILLE H	62	0.80	0.10	44	3	41	1080*	44	5630
MANNVILLE (OTHER)	42	0.85	0.15	31		31	1080*	33	
MANNVILLE ASSOC	4	0.80	0.15	3		3	1080*	3	
BSL MANN A - JUR D	230	0.85	0.10	180	28	152	1080*	164	5860
JURASSIC A	75	0.80	0.04	58	4	54	1080*	58	6050
JURASSIC C	19	0.80	0.04	15	10	5	1080*	5	2010
JURASSIC E	86	0.80	0.04	66	3	63	1080*	68	7840
JURASSIC (OTHER)	8	0.80	0.05	6		6	1080*	6	
JURASSIC B ASSOC	18	0.75	0.04	13		13	1080*	14	1220
RUNDLE C	260	0.85	0.05	210	72	138	1080*	149	8070
RUNDLE D	150	0.85	0.05	120	37	83	1080*	90	11240
RUNDLE H	16	0.85	0.05	13		13	1080*	14	2420
RUNDLE (OTHER)	17	0.85	0.05	13		13	1080*	14	
WABAMUN	7	0.90	0.20	5		5	1170	6	
GLENEVIS									
MANNVILLE	16	0.80	0.10	12		12	1040	12	
GLEN PARK									
MANNVILLE	6	0.80	0.05	4		4	1140	5	

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
7	0.24	0.20	690	70	0.92	0.58	2080	1916	1953 CWNG	2
									1966 LOCAL UTILITY	5
11	0.15	0.40	1480	140	0.85	0.67	5620	1957	1967	8
									1967	9
									1967	10
									1967	11
									1968	14
									1964	17
									1967	18
									1964	19
125	0.05	0.20	3760	220	0.94	0.75	10010	1954	1964	20
									1964	22
85	0.05	0.20	3700	220	0.95	0.77	9880	1956	1964	23
									1967	26
6	0.20	0.35	1510	120	0.81	0.69	4580	1964	1967 TCPL	27
18	0.20	0.35	1520	125	0.81	0.67	4780	1955	1967 TCPL	28
14	0.20	0.35	1550	115	0.81	0.70	4640	1965	1967	29
18	0.20	0.45	1550	125	0.82	0.68	4850	1955	1969 TCPL	31
									1967 TCPL	32
6	0.18	0.50	1520	110	0.75	0.76	4580	1963	1967 TCPL	33
									1967 TCPL	34
15	0.05	0.30	1620	125	0.82	0.69	5060	1962	1967	35
									1967 TCPL	37
									1965	40
									1965	41
27	0.11	0.30	2250	160	0.83	0.70	6930	1962	1966 TCPL	42
20	0.12	0.35	2300	155	0.81	0.71	6880	1956	1965 TCPL	43
									1966	45
									1967	46
53	0.14	0.30	2310	155	0.81	0.72	7130	1956	1967 TCPL	47
17	0.14	0.30	2300	150	0.81	0.73	6840	1953	1968 TCPL	48
13	0.15	0.30	2280	155	0.82	0.73	6920	1955	1968 TCPL	49
18	0.13	0.35	2320	155	0.81	0.73	7030	1961	1968 TCPL	51
									1968	52
16	0.16	0.20	2310	160	0.82	0.73	6990	1958	1968	53
55	0.10	0.15	2290	160	0.82	0.73	6970	1955	1968 TCPL	54
32	0.07	0.20	2280	155	0.82	0.73	6770	1955	1968 TCPL	55
29	0.04	0.20	2320	170	0.83	0.72	7210	1961	1968	57
									1968	58
									1961	59
									1966	62
									1965 NUL	65

TABLE A-1 (CONTINUED) - ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
GLEN PARK (CONTINUED)									
LEDUC SOLN	16	0.65	0.15	9	1	8	1250	10	
GOLD CREEK									
SPIRIT RIVER A	58	0.85	0.05	47		47	1050	49	3940
BLUESKY-GETHING A	63	0.85	0.10	48		48	1050	50	10230
GETHING	4	0.85	0.10	3		3	1050	3	
CADOMIN	11	0.80	0.15	9		9	1110*	10	
WABAMUN A	410	0.80	0.30	230		230	1040*	239	9400
WABAMUN B	92	0.80	0.30	51		51	1040*	53	1100
GOLDEN SPIKE									
VIKING	8	0.80	0.05	6	1	5	1050	5	
BLAIRMORE	14	0.80	0.05	11	1	10	1050	11	
D-1 A	25	0.90	0.10	20	12	8	1060	8	1260
D-2 ASSOC	3	0.85	0.15	3		3	1120	3	
D-2 SOLN	8	0.65	0.20	4	1	3	1120*	3	
D-3 A ASSOC		0.90	0.10		-51	51	1100*	56	
D-3 A SOLN	130	0.90	0.40	69	24	45	1130*	51	
GOODWIN									
MANNVILLE	1	0.75	0.10	1		1	1050	1	
JURASSIC A	20	0.85	0.10	15		15	1070	16	4560
GORDONDALE									
PEACE RIVER A	34	0.85	0.05	27	25	2	1000	2	9190
PEACE RIVER (OTHER)	1	0.85	0.05	1		1	1000	1	
GETHING A	39	0.85	0.05	29	22	7	1020	7	7850
GETHING (OTHER)	17	0.85	0.05	14	8	6	1020	6	
GREENCOURT									
JURASSIC A	39	0.80	0.10	28		28	1070	30	7800
JURASSIC B	14	0.80	0.05	10		10	1070	11	3770
PEKISKO	3	0.80	0.05	2		2	1130	2	
PEKISKO A ASSOC	110	0.85	0.10	85		85	1130	96	7110
HACKETT									
MANNVILLE A	60	0.90	0.10	49	9	40	1100	44	3420
MANNVILLE (OTHER)	2	0.90	0.10	1		1	1100	1	
HAIRY HILL									
VIKING	2	0.75	0.05	1		1	980	1	
COLONY A	22	0.90	0.05	19	13	6	1000*	6	3220
MANNVILLE (OTHER)	1	0.85	0.05	1		1	1000*	1	
NISKU	3	0.80	0.05	2		2	1000	2	
HALLIDAY									
VIKING	5	0.80	0.05	4	1	3	1040	3	
HAMELIN CREEK									
CADOTTE	3	0.80	0.05	2		2	1000	2	
GETHING	3	0.80	0.05	3		3	1010	3	
CADOMIN A	37	0.85	0.05	30	5	25	1060	27	
TRIASSIC	2	0.75	0.05	1		1	1160	1	
HANNA									
VIKING	10	0.85	0.05	8		8	1040	8	
MANNVILLE	3	0.85	0.05	2		2	1050	2	
BANFF	2	0.80	0.05	1		1	1080	1	
HARMATTAN EAST									
RUNDLE ASSOC	1060	0.85	0.11	800	-19	819	1080*	885	49300

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
									1966 NUL	2
24	0.15	0.15	1930	150	0.85	0.65	6470	1968	1968	5
6	0.12	0.20	3210	160	0.82	0.73	7110	1968	1969	6
									1968	7
									1968	8
64	0.07	0.15	5150	215	1.00	0.99	10880	1964	1967	10
122	0.07	0.15	5150	215	1.00	0.99	10900	1964	1968	11
									1965 INJECTED INTO D-3	14
									1968 INJECTED INTO D-3	15
53	0.09	0.20	1580	125	0.82	0.68	4440	1949	1955 INJECTED INTO D-3	16
									1966	17
									1965 INJECTED INTO D-3	19
									1968	20
							5650	1949	1966 INJECTED INTO D-3	21
									1964	24
13	0.20	0.30	2010	160	0.86	0.66	5900	1956	1964	25
15	0.19	0.30	620	90	0.93	0.57	2740	1952	1962 WESTCOAST	28
									1962	29
11	0.12	0.30	1470	110	0.85	0.60	4240	1953	1962 WESTCOAST	30
									1965 WESTCOAST	31
18	0.13	0.55	1600	140	0.83	0.69	4730	1958	1969	34
11	0.15	0.45	1600	140	0.83	0.69	4810	1967	1969	35
									1968	36
35	0.12	0.25	1620	145	0.85	0.64	4730	1961	1969	37
105	0.18	0.30	1220	135	0.85	0.65	3840	1952	1963 TCPL	40
									1963	41
									1961	44
21	0.24	0.30	630	70	0.91	0.60	1790	1954	1961 WESTERN MINERALS	45
									1966	46
									1966	47
									1961 TCPL	50
									1962	53
									1961	54
		GIP BASED ON MATERIAL BALANCE					3310	1951	1968 LOCAL UTILITY	55
									1961	56
									1966	59
									1957	60
									1957 LOCAL UTILITY	61
30	0.10	0.25	3430	185	0.84	0.84	8390	1954	1969 POOL BEING CYCLED	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU. FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
HARMATTAN EAST (CONTINUED)									
RUNDLE SOLN	170	0.55	0.25	71	19	52	1080*	56	
HARMATTAN-ELKTON									
BLAIRMORE	3	0.90	0.05	2		2	1020	2	
RUNDLE A	55	0.85	0.15	40	5	35	1100	39	2740
RUNDLE B ASSOC	28	0.85	0.15	21	9	12	1080*	13	7140
RUNDLE C ASSOC	1150	0.90	0.15	880	-54	934	1080*	1009	19020
RUNDLE C SOLN	180	0.65	0.30	83	44	39	1080*	42	
D-3 A	600	0.80	0.65	170	9	161	960	155	13970
HEART RIVER									
CADOTTE	2	0.85	0.05	2	1	1	1000	1	
NOTIKEWIN	2	0.90	0.05	2	1	1	1000	1	
HERCULES									
VIKING	20	0.85	0.05	17		17	1050	18	
MANNVILLE	16	0.80	0.05	13	1	12	960	12	
HIGH PRAIRIE									
CADOTTE	3	0.85	0.05	3		3	1000	3	
NOTIKEWIN	8	0.85	0.05	6		6	1100	7	
GETHING	2	0.85	0.05	1		1	1000	1	
HOLBURN									
CARDIUM	8	0.80	0.05	6	3	3	980	3	
MANNVILLE	16	0.85	0.10	12	1	11	1120	12	
HOLMBERG									
MANNVILLE A	15	0.85	0.05	12		12	1050	13	2100
MANNVILLE (OTHER)	11	0.85	0.05	9		9	1050	9	
HOMEGLEN-RIMBEY									
D-3 ASSOC	1170	0.75	0.15	760**					12800
D-3 SOLN	86	0.50	0.15	37**	275**	522	1020*	532	
HUNTER VALLEY									
RUNDLE A	73	0.85	0.25	47		47	1000	47	1570
RUNDLE (OTHER)	5	0.85	0.25	3		3	1000	3	
HUSSAR									
BELLY RIVER	4	0.75	0.05	3	2	1	1000	1	
VIKING E	24	0.80	0.05	18	5	13	1020*	13	13590
VIKING (OTHER)	17	0.80	0.05	13	3	10	1020*	10	
VIKING B ASSOC	32	0.75	0.05	22	3	19	1020*	19	13000
BASAL COLORADO A	26	0.75	0.05	19	8	11	1020*	11	16390
BASAL COLORADO C	26	0.75	0.05	19	9	10	1030*	10	16080
BSL COLORADO (OTHER)	4	0.80	0.05	3	1	2	1030*	2	
GLAUCONITIC N	130	0.85	0.05	100	58	42	1030*	43	12460
GLAUCONITIC P	17	0.85	0.05	14		14	1030*	14	500
GLAUCONITIC R	20	0.85	0.05	16	10	6	1030*	6	500
GLAUCONITIC A ASSOC	75	0.85	0.05	61	27	34	1030*	35	5290
GLAUCONITIC B ASSOC	19	0.85	0.05	15	11	4	1030*	4	3900
GLAUCONITIC A SOLN	20	0.65	0.25	10		10	1030*	10	
OSTRACOD R	26	0.85	0.05	21	2	19	1030*	20	7480
OSTRACOD F ASSOC	27	0.80	0.05	20	1	19	1030*	20	8300
BASAL MANNVILLE B	30	0.85	0.05	25		25	1030*	26	1330
BASAL MANNVILLE D	11	0.90	0.05	10	1	9	1030*	9	530
MANNVILLE (OTHER)	102	0.85	0.05	82	26	56	1030*	58	
MANN ASSOC (OTHER)	29	0.85	0.05	23	2	21	1030*	22	

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
							8620	1957	1966 INJ INTO GAS CAP
									1966
35	0.08	0.20	3630	205	0.89	0.71	9150	1957	1964 TCPL
6	0.09	0.20	3430	195	0.85	0.82	8960	1955	1964 INJ INTO RUNDLE C
70	0.11	0.20	3630	200	0.84	0.84	8990	1954	1964 POOL BEING CYCLED
							9130	1955	1966 INJ INTO GAS CAP
67	0.05	0.10	4680	230	0.75	0.93	11000	1961	1967 A&S
									1964 LOCAL UTILITY
									1964 LOCAL UTILITY
									1955
									1966 NUL
									1961 CONSIDERED BEYOND
									1961 ECONOMIC REACH
									1961
									1966 GOLDEN SPIKE INJ
									1968 GOLDEN SPIKE INJ
13	0.20	0.30	1100	95	0.81	0.70	3420	1952	1960 BAROID OF CANADA
									1958
173	0.07	0.10	2830	180	0.85	0.70	7840	1953	1964 TCPL AND A&S
							7920	1953	1964 TCPL AND A&S
83	0.07	0.20	3580	145	0.84	0.68	9280	1962	1964
									1964
									1961 TCPL
4	0.20	0.30	1150	100	0.89	0.63	3740	1961	1966 TCPL
									1961 TCPL
5	0.20	0.30	1120	105	0.88	0.63	4040	1955	1961 TCPL
3	0.17	0.30	1240	110	0.88	0.61	4330	1952	1961 TCPL
4	0.18	0.30	1230	110	0.88	0.63	4120	1955	1964 TCPL
									1965 TCPL
14	0.21	0.30	1470	110	0.83	0.64	4470	1955	1968 TCPL
48	0.21	0.30	1490	110	0.82	0.65	4510	1957	1968
56	0.21	0.30	1490	110	0.83	0.64	4650	1960	1967 TCPL
17	0.22	0.25	1480	110	0.83	0.64	4690	1952	1967 TCPL
7	0.20	0.30	1470	110	0.83	0.67	4700	1956	1967 TCPL
							4650	1957	1967
5	0.20	0.35	1510	115	0.82	0.65	4660	1956	1965 TCPL
5	0.21	0.25	1370	110	0.84	0.65	4570	1956	1964 TCPL
45	0.15	0.30	1470	105	0.82	0.67	4330	1960	1963
38	0.16	0.30	1510	115	0.83	0.66	4820	1955	1961 TCPL
									1968 TCPL
									1968 TCPL

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
INLAND									
VIKING A	17	0.80	0.05	13		13	980	13	15300
MANNVILLE	2	0.80	0.10	1		1	1000	1	
INNISFAIL									
BLAIRMORE ASSOC	1	0.80	0.15	1		1	1050	1	
RUNDLE	22	0.90	0.10	18		18	1080	19	
WABAMUN	3	0.85	0.15	2		2	1080	2	
D-3 ASSOC	17	0.90	0.35	10		10	1020	10	1220
D-3 SOLN	200	0.55	0.45	60	18	42	1130*	47	
IRRICANA									
WABAMUN A	27	0.85	0.50	11		11	980	11	3296
JARVIE									
VIKING	10	0.80	0.05	7		7	1040	7	
MANNVILLE	9	0.85	0.05	8		8	1100	9	
JENNER									
BOW ISLAND	5	0.75	0.05	3		3	990	3	
BASAL COLORADO	8	0.85	0.05	6		6	1040	6	
BASAL COLORADO ASSOC	1	0.85	0.15	1		1	1040	1	
MANNVILLE	20	0.80	0.05	15		15	1050	16	
MANNVILLE ASSOC	15	0.80	0.05	12		12	1050	13	
PEKISKO ASSOC	3	0.85	0.05	2		2	1000	2	
JOARCAM									
VIKING	3	0.75	0.05	2		2	1040	2	
VIKING ASSOC	70	0.75	0.35	35	-2	37	1040	38	13520
VIKING SOLN	42	0.35	0.65	9	2	7	1050	7	
MANNVILLE 30-50-22	15	0.90	0.05	13		13	960	12	500
MANNVILLE (OTHER)	3	0.90	0.05	3		3	960	3	
JOFFRE									
VIKING	1	0.75	0.10	1		1	1000	1	
BLAIRMORE	41	0.85	0.10	32	1	31	1020	32	
LEDUC ASSOC	2	0.85	0.15	2		2	1050	2	
JUDY CREEK									
VIKING A	54	0.80	0.05	41	10	31	1010	31	23320
BHL LK A SOLN	560	0.45	0.30	180	20	160	1090*	174	
BHL LK B SOLN	270	0.50	0.30	93	10	83	1090*	90	
JUDY CREEK SOUTH									
RUNDLE A	13	0.90	0.10	10		10	1050*	11	500
JUMPING POUND									
MISSISSIPPIAN	780	0.85	0.15	560	277	283	1050*	297	7090
JUMPING POUND WEST									
RUNDLE A	750	0.80	0.20	480	14	466	1050*	489	9060
RUNDLE B	270	0.80	0.20	170	4	166	1050*	174	3570
RUNDLE C	150	0.80	0.20	94		94	1050*	99	2000
KAYBOB									
NOTIKEWIN A	200	0.85	0.05	160	29	131	1100*	144	25650
NOTIKEWIN B	170	0.85	0.05	140	55	85	1100*	94	
NOTIKEWIN D	17	0.85	0.05	14		14	1100*	15	5660
NOTIKEWIN (OTHER)	6	0.85	0.05	5		5	1100*	6	

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11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
3	0.22	0.40	800	80	0.90	0.60	2190	1959	1963 CONSIDERED BEYOND	2
									1963 ECONOMIC REACH	3
										4
										5
									1965	6
									1961	7
									1961	8
28	0.06	0.15	3550	95	0.84	0.81	8440	1957	1961	9
										10
							8580	1957	1965 TCPL	11
										12
										13
13	0.06	0.85	3530	625	0.71	0.90	7602	1958	1968 WESTCOAST	14
										15
										16
									1960 CONSIDERED BEYOND	17
									1956 ECONOMIC REACH	18
										19
										20
									1961	21
									1961	22
									1969	23
									1961	24
										25
									1966	26
									1965	27
										28
										29
									1963	30
19	0.17	0.40	870	100	0.89	0.65	3240	1949	1968	31
							3250	1949	1968 GAS FLOOD	32
57	0.20	0.35	1250	100	0.86	0.60	3980	1960	1961	33
										34
									1961	35
										36
										37
									1967	38
									1967	39
									1967	40
										41
										42
5	0.18	0.35	1290	130	0.88	0.63	4610	1959	1968 NUL AND A&S	43
							8660	1959	1966 NUL AND A&S	44
							8840	1959	1966 NUL AND A&S	45
										46
										47
56	0.10	0.20	1900	155	0.86	0.63	6040	1960	1960 CONSIDERED BEYOND	48
									ECONOMIC REACH	49
										50
										51
141	0.08	0.10	3980	195	0.90	0.71	9590	1944	1964 CWNG	52
										53
										54
134	0.07	0.15	4250	185	0.92	0.74	10950	1961	1968 CWNG	55
130	0.07	0.15	4320	190	0.93	0.75	11950	1963	1968 CWNG	56
130	0.06	0.15	4350	180	0.91	0.75	11500	1967	1968	57
										58
										59
13	0.20	0.35	1530	135	0.88	0.61	4690	1957	1967 A&S	60
		GIP BASED ON MATERIAL BALANCE					4820	1958	1968 A&S	61
6	0.19	0.35	1390	145	0.88	0.61	5050	1958	1966	62
									1966	63

TABLE A-1 (CONTINUED) - ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
KAYBOB (CONTINUED)									
SPIRIT RIVER	8	0.85	0.05	7		7	1000	7	
GETHING	16	0.85	0.05	13		13	1050	14	
CADOMIN	48	0.85	0.05	38		38	1040	40	
CADOMIN B ASSOC	76	0.85	0.05	62		62	1040	64	6110
CADOMIN ASSOC	6	0.80	0.05	4		4	1040	4	
WABAMUN	1	0.80	0.10	1		1	1070	1	
NISKU	5	0.85	0.35	3		3	1070	3	
BEAVERHILL LAKE	1	0.80	0.15	1		1	1070	1	
BHL LK ASSOC	6	0.80	0.15	4		4	1140*	5	
BHL LK A SOLN	340	0.40	0.25	100	14	86	1140*	98	
KAYBOB SOUTH									
VIKING A	30	0.75	0.05	21	1	20	1120	22	30350
CADOMIN A	39	0.80	0.05	30		30	1070*	32	8390
CADOMIN B	27	0.80	0.05	20		20	1070*	21	3430
CADOMIN C	17	0.80	0.05	13		13	1070*	14	3122
CADOMIN (OTHER)	8	0.75	0.05	6		6	1070*	6	
TRIASSIC	3	0.80	0.05	2		2	1160*	2	
TRIASSIC ASSOC	2	0.80	0.05	2		2	1160*	2	
TRIASSIC SOLN	100	0.40	0.25	30		30	1160*	35	
NISKU A	19	0.90	0.20	14		14	1160*	16	1100
NISKU (OTHER)	1	0.80	0.05	1		1	1160*	1	
BEAVERHILL LAKE A	4040	0.80	0.35	2100		2100	1090*	2289	60360
KILLAM									
VIKING	6	0.80	0.05	4		4	1010	4	
MANNVILLE	14	0.75	0.05	10		10	1000	10	
NISKU	1	0.80	0.05	1		1	1170	1	
KILLAM NORTH									
MANNVILLE	19	0.80	0.05	15	1	14	1000	14	
MANNVILLE ASSOC	5	0.80	0.05	4		4	1000	4	
KNAPPEN									
MANNVILLE	6	0.80	0.05	5		5	1000	5	
SAWTOOTH	8	0.80	0.05	6		6	1000	6	
MISSISSIPPIAN	7	0.90	0.10	6		6	1000	6	
KNELLER									
MANNVILLE	11	0.85	0.05	9		9	1000	9	
KNOPCIK									
DOE CREEK A	18	0.75	0.05	12	1	11	1000	11	4360
PADDY	1	0.80	0.05	1		1	1020	1	
LAC LA BICHE									
MANNVILLE	10	0.80	0.05	8	1	7	1010	7	
LAMBERT CREEK									
WABAMUN 4-51-21	14	0.75	0.05	10		10	1050	11	1100
LEAHURST									
MANNVILLE	25	0.65	0.05	15	2	13	1160*	15	
LEDUC-WOODBEND									
CARDIUM	12	0.80	0.05	9	7	2	1040	2	
VIKING	20	0.80	0.05	15	3	12	1070	13	
BLAIRMORE	34	0.85	0.05	26	22	4	1180	5	
BLAIRMORE ASSOC	57	0.85	0.05	45	2	43	1180	51	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1964	2
									1964	3
									1964	4
17	0.16	0.30	2210	160	0.84	0.72	5800	1962	1964	5
									1968	6
										7
									1961	8
									1961	9
									1964	10
									1962	11
							9780	1957	1965 A&S	12
										13
										14
3	0.14	0.40	1460	150	0.86	0.66	5710	1960	1968	15
8	0.15	0.35	2230	180	0.87	0.64	6710	1961	1966	16
13	0.15	0.35	2230	180	0.87	0.64	6750	1963	1966	17
9	0.15	0.35	2230	180	0.87	0.64	6750	1961	1966	18
										19
									1967	20
									1964 TCPL	21
									1963	22
							6980	1962	1965	23
4	0.05	0.20	4100	225	0.93	0.80	9510	1958	1963	24
										25
									1958	26
94	0.07	0.20	4690	240	0.90	1.00	10560	1961	1969 POOL BEING CYCLED	27
										28
										29
									1968	30
									1968	31
									1968	32
										33
										34
									1966 LOCAL UTILITY	35
									1966	36
										37
										38
									1966 CMG	39
									1967 CMG	40
									1965	41
										42
										43
									1968	44
										45
										46
9	0.22	0.30	900	100	0.87	0.66	2920	1964	1966 LOCAL UTILITY	47
									1964	48
										49
										50
									1968 LOCAL UTILITY	51
										52
										53
48	0.03	0.20	5500	250	1.05	0.79	12870	1957	1958 CONSIDERED BEYOND	54
									ECONOMIC REACH	55
										56
										57
									1969 LOCAL UTILITY	58
										59
										60
									1967 INJECTED INTO NISKU	61
									1959 AND LEDUC GAS CAPS	62
									1959 AND SOLD TO NUL	63
									1961	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
LEDUC-WOODBEND (CONTINUED)									
D-1	2	0.85	0.10	2	2	¤ 1	1050	¤ 1	
D-1 ASSOC	4	0.85	0.10	3		3	1050	3	
D-2A ASSOC	37	0.90	0.15	28	-12	40	1180	47	9770
D-2 A SOLN	130	0.75	0.30	70	63	7	1180	8	
D-2 B SOLN	41	0.75	0.30	21	15	6	1180	7	
D-3 A ASSOC	420	0.85	0.15	300	-7	307	1180	362	17490
D-3 ASSOC (OTHER)	6	0.85	0.15	4	1	3	1180	4	
D-3 A SOLN	140	0.70	0.30	70	59	11	1180	13	
D-3 SOLN (OTHER)	9	0.70	0.30	5	4	1	1180	1	
LEGAL									
MANNVILLE	6	0.75	0.05	4	2	2	1030	2	
LINDBERGH									
VIKING	4	0.65	0.05	2		2	990	2	
MANNVILLE	23	0.80	0.05	17	7	10	1000	10	
LITTLE BOW									
MANNVILLE	17	0.85	0.05	14	1	13	1000	13	
UPPER MANN A ASSOC	20	0.85	0.05	16	2	14	1000	14	3440
MANN ASSOC OTHER	1	0.85	0.05	1		1	1000	1	
LLOYDMINSTER									
MANNVILLE	24	0.85	0.30	14	12	2	950	2	
LONE PINE CREEK									
MANNVILLE	5	0.85	0.10	4		4	1020	4	
WABAMUN A	370	0.85	0.20	250	12	238	1000	238	28200
D-3 A ASSOC	77	0.85	0.25	48**					2420
D-3 A SOLN	10	0.65	0.30	5**					
					2**	51	1060*	54	
D-3 ASSOC (OTHER)	9	0.85	0.20	6		6	1060*	6	
LONG COULEE									
MANNVILLE A	16	0.85	0.25	10	1	9	1000	9	2070
MANNVILLE (OTHER)	11	0.85	0.20	7		7	1000	7	
LOOKOUT BUTTE									
RUNDLE A	660	0.80	0.15	450	28	422	1060*	447	7280
LOVETT RIVER									
BLAIRMORE 2-47-19	12	0.90	0.05	10		10	1040	10	1100
RUNDLE A	97	0.80	0.10	70		70	1040	73	1100
MAJEAU LAKE									
MANNVILLE	2	0.80	0.05	2		2	1000	2	
MISS 25-56-4	12	0.90	0.10	10		10	1070	11	500
MALMO									
VIKING	8	0.85	0.05	6		6	1000	6	
BLAIRMORE	8	0.85	0.10	6		6	1030	6	
BLAIRMORE ASSOC	2	0.70	0.15	1		1	1030	1	
NISKU ASSOC	4	0.80	0.20	3		3	1100	3	
D-3 B	42	0.85	0.20	29		29	1100	32	1960
D-3 ASSOC	2	0.85	0.15	1		1	1100	1	
MANYBERRIES									
BOW ISLAND A	28	0.90	0.02	25	23	2	940	2	
BOW ISLAND (OTHER)	5	0.65	0.02	3		3	940	3	
MANNVILLE	2	0.80	0.05	1		1	1000	1	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1969	2
									1966	3
41	0.02	0.20	1780	150	0.80	0.73	5050	1947	1958	4
							5100	1947	1965	5
							5260	1947	1965	6
										7
60	0.08	0.15	1890	150	0.83	0.66	5300	1947	1964	8
									1964	9
							5320	1947	1966	10
									1966	11
										12
										13
									1955 CIGOL	14
										15
										16
									1961 CANSALT	17
									1961 CANSALT	18
										19
										20
									1968	21
8	0.21	0.40	1680	105	0.82	0.67	3950	1965	1968 TCPL	22
									1968	23
										24
										25
									1966 LOCAL UTILITY	26
										27
										28
									1963	29
33	0.05	0.20	3570	180	0.89	0.76	7850	1955	1969 TCPL	30
47	0.08	0.15	3260	175	0.84	0.81	7990	1963	1967 TCPL	31
							8010	1963	1967 TCPL	32
										33
									1967	34
										35
										36
9	0.20	0.35	1880	105	0.78	0.83	4380	1965	1968 TCPL	37
									1968	38
										39
										40
153	0.07	0.20	4770	190	0.96	0.72	12060	1959	1967 TCPL	41
										42
										43
9	0.15	0.25	4300	190	0.96	0.62	10010	1959	1959	44
177	0.06	0.20	4950	220	1.01	0.61	11870	1958	1959	45
										46
										47
									1955 CONSIDERED BEYOND	48
60	0.09	0.15	1500	125	0.82	0.67	4250	1951	1955 ECONOMIC REACH	49
										50
										51
									1960	52
									1959	53
									1960	54
									1959	55
										56
46	0.07	0.10	2180	130	0.81	0.76	5990	1959	1966	57
									1966	58
										59
										60
		GIP BASED ON MATERIAL BALANCE					2570	1947	1967 CMG	61
									1967	62
									1957	63

TABLE A-1 (CONTINUED) - ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
MARLBORO									
LEDUC A	63	0.85	0.25	40		40	1000	40	500
MARSH HEAD CREEK									
LEDUC 17-59-20	27	0.85	0.35	15		15	1050	16	500
MARTEN HILLS									
PELICAN	2	0.65	0.05	1		1	990	1	
WABISKAW A	770	0.75	0.05	550		550	990	545	166000
MANNVILLE (OTHER)	16	0.75	0.05	11		11	990	11	
WABAMUN A	330	0.75	0.05	240		240	1000	240	79640
WABAMUN (OTHER)	10	0.75	0.05	7		7	1000	7	
MATZIWIN									
VIKING	11	0.85	0.05	9		9	1090	10	
MANNVILLE	1	0.80	0.05	1		1	1090	1	
MAZEPPA									
MISS 16-19-27	20	0.90	0.15	15		15	1060	16	1100
WABAMUN	11	0.85	0.45	5		5	1000	5	
MEDICINE HAT									
MEDICINE HAT	2550	0.80	0.02	2000	597	1403	970	1361	983680
BOW ISLAND	15	0.60	0.05	9	1	8	970	8	
SAWTOOTH	6	0.80	0.05	5	2	3	1000	3	
MEDICINE RIVER									
BASAL MANNVILLE A	34	0.85	0.15	25		25	1150*	29	3680
MANNVILLE (OTHER)	73	0.85	0.15	53		53	1150*	61	
OSTRACOD B ASSOC	14	0.85	0.15	10		10	1150*	12	3980
OSTRACOD C ASSOC	40	0.85	0.15	29	3	26	1150*	30	2900
BASAL QUARTZ B ASSOC	32	0.85	0.15	23		23	1150*	26	2310
MANN ASSOC (OTHER)	18	0.85	0.15	13		13	1150*	15	
MANN SOLN	43	0.60	0.45	12		12	1150*	14	
JURASSIC	15	0.85	0.15	11		11	1020*	11	
JURASSIC D ASSOC	15	0.80	0.15	10		10	1020*	10	910
JUR ASSOC (OTHER)	16	0.80	0.15	11		11	1020*	11	
JURASSIC SOLN	70	0.65	0.45	25		25	1020*	26	
RUNDLE	20	0.85	0.15	14	1	13	1100*	14	
RUNDLE ASSOC	9	0.85	0.15	6		6	1100*	7	
RUNDLE SOLN	36	0.60	0.45	12		12	1200*	14	
LEDUC ASSOC	2	0.85	0.20	1		1	1100*	1	
MILLET									
MANNVILLE 1-49-25	25	0.50	0.05	12		12	1020	12	5880
MANNVILLE (OTHER)	5	0.80	0.10	3		3	1020	3	
MINNEHIK-BUCK LAKE									
BLAIRMORE	6	0.80	0.05	4		4	1000	4	
PEKISKO A	630	0.85	0.07	500	114	386	1120*	432	
PEKISKO B	71	0.85	0.10	54	1	53	1120*	59	7620
MITSUE									
MANNVILLE	2	0.80	0.05	1		1	1070	1	
GILWOOD ASSOC	3	0.90	0.25	2		2	1170	2	
GILWOOD A SOLN	470	0.50	0.25	180		180	1170	211	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
173	0.07	0.10	4960	250	0.96	0.74	12140	1965	1966
29	0.06	0.15	4800	245	0.92	0.66	11540	1961	1964 CONSIDERED BEYOND ECONOMIC REACH
									1964
19	0.29	0.30	390	80	0.95	0.57	2250	1961	1968
									1969
40	0.15	0.40	390	80	0.95	0.57	2260	1961	1968
									1967
									1962
									1961
33	0.08	0.20	2700	145	0.81	0.71	6800	1956	1957 CONSIDERED BEYOND ECONOMIC REACH
									1967
8	0.26	0.40	630	60	0.91	0.57	1600	1904	1967 TCPL, MANY ISLANDS AND LOCAL UTILITY
									1964 TCPL
									1968 TCPL
12	0.14	0.30	2640	160	0.81	0.71	7660	1958	1968
									1968
5	0.13	0.35	2830	155	0.80	0.76	7010	1954	1968
14	0.14	0.25	2930	150	0.79	0.76	7480	1960	1968 TCPL
19	0.14	0.30	2380	150	0.81	0.72	7000	1959	1968
									1968
									1968
									1968
22	0.15	0.30	2340	145	0.81	0.70	6970	1962	1968
									1968
									1968
									1968 TCPL
									1968
									1968
									1968
7	0.20	0.70	1500	120	0.79	0.71	4440	1951	1968 CONSIDERED BEYOND
									1957 ECONOMIC REACH
									1959
		GIP BASED ON MATERIAL BALANCE					6910	1952	1968 A&S
19	0.10	0.25	2490	185	0.85	0.71	7300	1962	1966 A & S
									1968
									1966
							5680	1964	1968

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
MOOSE									
RUNDLE A	86	0.80	0.20	55		55	1000	55	1900
MORINVILLE									
VIKING	4	0.75	0.05	3		3	1000	3	
MANNVILLE	130	0.80	0.10	96	45	51	1070*	55	
MOUNTAIN PARK									
TRIASSIC 36-47-22	21	0.85	0.05	17		17	1090	19	1100
MURIEL LAKE									
MANNVILLE	9	0.75	0.05	6	1	5	1000	5	
NEVIS									
BLAIRMORE A	64	0.85	0.10	49		49	1000	49	11990
BLAIRMORE (OTHER)	2	0.85	0.10	1		1	1000	1	
DEVONIAN	1040	0.90	0.15	800	183	617	1000*	617	31000
NEW NORWAY									
VIKING	3	0.80	0.10	2		2	1000	2	
BLAIRMORE	10	0.85	0.05	9		9	1010	9	
NIPISI									
GILWOOD A SOLN	250	0.55	0.25	110		110	1150	127	
NITON									
BLAIRMORE	13	0.80	0.05	10		10	1070	11	
CADOMIN	8	0.90	0.05	7		7	1070	7	
NORDEGG									
TRIASSIC	9	0.90	0.10	7		7	1000	7	
RUNDLE 17-41-17	25	0.90	0.10	20		20	1000	20	2130
NORMANDVILLE									
PEACE RIVER	1	0.70	0.05	1		1	990	1	
GETHING	6	0.85	0.05	5		5	980	5	
TRIASSIC	1	0.85	0.05	1		1	1090	1	
BELLOY	2	0.85	0.05	2		2	1060	2	
MISSISSIPPIAN A	16	0.85	0.05	13	2	11	1050	12	1410
MISS (OTHER)	22	0.85	0.05	18	1	17	1050	18	
OBED									
VIKING 26-55-22	14	0.85	0.05	12		12	1020	12	1100
MANNVILLE	6	0.85	0.05	5		5	1040	5	
RUNDLE	4	0.85	0.10	4		4	1050	4	
D-2 A	580	0.90	0.35	130		130	1060	138	
OBERLIN									
MANNVILLE	3	0.70	0.05	2	2	□ 1	1090	□ 1	
OKOTOKS									
CROSSFIELD	470	0.80	0.55	170	51	119	1000	119	21990
OLDS									
WABAMUN B	31	0.85	0.25	20		20	1000*	20	1100
WABAMUN A ASSOC	350	0.85	0.25	220	46	174	1000*	174	31030
WABAMUN SOLN	62	0.65	0.40	24		24	1000*	24	
OPEN CREEK									
BASAL QUARTZ A	14	0.85	0.10	11		11	1080*	12	500

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11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS
140	0.06	0.15	1870	115	0.77	0.73	7570	1960	1969
									1962
									1962 CIGOL AND LOCAL UTILITY .
36	0.07	0.20	4100	240	0.98	0.62	10120	1956	1969 CONSIDERED BEYOND ECONOMIC REACH
									1964 LOCAL UTILITY
7	0.22	0.20	1400	130	0.84	0.66	4750	1952	1959
									1964
75	0.07	0.15	2340	140	0.81	0.69	5580	1952	1968 TCPL
									1959
									1959
									1965 CONSIDERED BEYOND ECONOMIC REACH
									1966
									1963
									1961 CONSIDERED BEYOND
70	0.04	0.20	1840	125	0.86	0.58	4930	1960	1961 ECONOMIC REACH
									1967
									1967
									1967
									1967
13	0.27	0.35	1570	100	0.83	0.64	3440	1956	1967 LOCAL UTILITY
									1967 LOCAL UTILITY
15	0.14	0.40	3830	165	0.92	0.62	8080	1967	1967
									1969
									1966
									1969
									1967 LOCAL UTILITY
39	0.06	0.20	3600	175	0.70	0.90	8710	1951	1966 CWNG
68	0.05	0.20	3600	165	0.83	0.75	8600	1959	1967 TCPL
27	0.05	0.20	3590	165	0.83	0.75	8680	1952	1967 TCPL
							8990	1965	1967 TCPL
38	0.14	0.35	2800	180	0.84	0.71	7190	1967	1968

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
OPEN CREEK (CONTINUED)									
MANNVILLE (OTHER)	19	0.90	0.15	14		14	1080*	15	
PEKISKO	11	0.85	0.10	8		8	1080*	9	
OWLSEYE									
MANNVILLE	2	0.85	0.05	2		2	1020	2	
OYEN									
VIKING A	36	0.85	0.05	29	5	24	980	24	6750
VIKING (OTHER)	8	0.80	0.05	6	5	1	980	1	
DETRITAL	11	0.85	0.05	9	2	7	1010	7	
PADDLE RIVER									
JURASSIC-DETRITAL	180	0.80	0.10	130	19	111	1130*	125	30000
RUNDLE	36	0.85	0.10	27		27	1060	29	9300
PAKOWKI LAKE									
BOW ISLAND A	21	0.65	0.05	13	8	5	940	5	21480
BOW ISLAND (OTHER)	5	0.85	0.05	4		4	940	4	
MANNVILLE	1	0.90	0.05	1		1	1000	1	
PARKLAND									
RUNDLE	3	0.85	0.15	2**	2**		1010		
PARKLAND NORTH-EAST									
RUNDLE 29-15-26	15	0.85	0.15	11		11	1010	11	2130
RUNDLE (OTHER)	5	0.90	0.15	4		4	1010	4	
PELICAN									
WABISKAW	18	0.70	0.05	12		12	990	12	
WABISKAW ASSOC	3	0.65	0.05	2		2	990	2	
PEMBINA									
KEYSTONE BR A	23	0.80	0.05	18		18	1070*	19	3230
BELLY RIVER (OTHER)	33	0.80	0.05	26	3	23	1070*	25	
BELLY RIVER ASSOC	25	0.80	0.05	19		19	1070*	20	
BELLY RIVER SOLN	90	0.45	0.80	9	3	6	1070*	6	
CARDIUM SOLN	4100	0.36	0.40	880	150	730	1130*	825	
VIKING	11	0.80	0.05	8		8	1130*	9	
GLAUCONITIC A	170	0.85	0.06	130	26	104	1130*	118	12600
GLAUCONITIC B	93	0.85	0.06	74	6	68	1130*	77	5180
GLAUCONITIC C & D	73	0.80	0.06	55		55	1130*	62	4970
MANNVILLE (OTHER)	19	0.75	0.05	14	3	11	1130*	12	
JURASSIC	18	0.85	0.05	15		15	1050*	16	
RUNDLE	13	0.85	0.10	10		10	1050*	11	
PENDANT D'OREILLE									
BOW ISLAND	200	0.85	0.05	160	99	61	940	57	86630
BOW ISLAND (OTHER)	4	0.85	0.05	3		3	940	3	
MANNVILLE A	47	0.90	0.05	40	20	20	1000	20	4480
MANNVILLE C	35	0.90	0.05	30	2	28	1000	28	2590
MANNVILLE (OTHER)	19	0.90	0.05	16		16	1000	16	
PENHOLD									
VIKING 33-36-28	14	0.90	0.05	12		12	1020	12	1650
PHIL CAN									
GETHING	11	0.85	0.05	8		8	980	8	
MISSISSIPPIAN	5	0.85	0.05	4		4	1050	4	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1968
									1968
									1961 LOCAL UTILITY
10	0.24	0.30	970	85	0.89	0.58	2570	1942	1965 TCPL
									1965 TCPL
									1965 TCPL
22	0.14	0.65	1780	140	0.82	0.70	5050	1956	1969 NUL
14	0.08	0.35	1780	130	0.81	0.82	5090	1956	1966
3	0.21	0.30	790	75	0.91	0.59	2200	1955	1967 CMG
									1967
									1967
									1963 POOL ABANDONED
16	0.07	0.25	2830	145	0.83	0.66	6940	1953	1963 CONSIDERED BEYOND
									1956 ECONOMIC REACH
									1968 CONSIDERED BEYOND
									1964 ECONOMIC REACH
18	0.19	0.35	1050	100	0.89	0.60	3180	1957	1965
									1965 NUL
									1965
									1965 NUL
							5080	1953	1967 NUL
									1956
25	0.14	0.40	1990	135	0.80	0.69	6000	1957	1968 A&S
23	0.16	0.30	1970	135	0.81	0.69	5640	1958	1968 NUL
24	0.15	0.35	1950	135	0.81	0.66	6080	1959	1968 NUL
									1959 NUL
									1965
									1966
6	0.22	0.25	710	75	0.92	0.59	2030	1946	1968 CMG
									1967
20	0.21	0.35	1150	85	0.87	0.58	2740	1961	1968 CMG
25	0.22	0.35	1160	85	0.87	0.58	2690	1965	1968 CMG
									1968 CMG
12	0.20	0.30	1710	145	0.89	0.69	5590	1958	1958 CONSIDERED BEYOND
									ECONOMIC REACH
									1961 CONSIDERED BEYOND
									1961 ECONOMIC REACH

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
PINCHER CREEK									
RUNDLE A	1800	0.40	0.25	540	252	288	1020*	294	14000
PINE CREEK									
WABAMUN	190	0.80	0.45	82	44	38	1050	40	9650
WABAMUN (OTHER)	30	0.85	0.45	14		14	1000	14	
D-3	770	0.40	0.35	200	149	51	1000	51	9480
PINE NORTH-WEST									
DEBOLT	8	0.85	0.10	6		6	1030	6	
D-3 A	360	0.75	0.25	200	14	186	980	182	4310
PLAIN									
VIKING	3	0.75	0.05	2		2	980	2	
MANNVILLE	15	0.80	0.05	11		11	1000	11	
PLOVER LAKE									
VIKING	18	0.90	0.05	15		15	1000	15	
POUCE COUPE									
PEACE RIVER A	150	0.70	0.05	100	89	11	1000	11	25700
PEACE RIVER (OTHER)	2	0.80	0.05	2		2	1000	2	
CADOMIN	4	0.85	0.05	3		3	1060	3	
POUCE COUPE SOUTH									
DOE CREEK	5	0.60	0.05	3	2	1	1000	1	
PEACE RIVER A	32	0.75	0.05	23	19	4	1040	4	6700
PEACE RIVER B	55	0.75	0.05	39	31	8	1040	8	8500
PEACE RIVER (OTHER)	5	0.70	0.05	3		3	1040	3	
CADOTTE	9	0.70	0.05	6		6	1040	6	
GETHING	16	0.80	0.05	12	11	1	1000	1	
CADOMIN	7	0.85	0.05	6	2	4	1000	4	
TRIASSIC	18	0.80	0.05	14		14	1000	14	
PREVO									
MANNVILLE	5	0.85	0.10	4		4	1020	4	
PEKISKO A	44	0.85	0.10	34	8	26	1110*	29	2490
PRINCESS									
2WS A	60	0.80	0.05	45	5	40	970	39	33310
2WS (OTHER)	7	0.75	0.05	5		5	970*	5	
BOW ISLAND	2	0.75	0.05	1		1	1010	1	
BASAL COLORADO	9	0.75	0.05	6	3	3	1020*	3	
BASAL MANNVILLE A	18	0.90	0.05	15	5	10	1020*	10	1050
BASAL MANNVILLE C	38	0.85	0.05	31	1	30	1020*	31	2220
MANNVILLE (OTHER)	21	0.85	0.05	17	9	8	1020*	8	
MANN ASSOC (OTHER)	14	0.90	0.05	12	10	2	1020*	2	
JEFFERSON B	30	0.85	0.05	24	4	20	1030*	21	6940
JEFFERSON ASSOC	1	0.85	0.05	1		1	1030*	1	
PROVOST									
VIKING A & B	1050	0.88	0.02	900	278	622	1030	641	

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS	
310	0.04	0.20	4940	190	0.97	0.72	12500	1948	1961 TCPL	2
26	0.07	0.15	4500	210	0.82	0.83	10080	1956	1967 MAINTAINS PRESSURE	5
									1965 IN WINDFALL D-3 A	6
122	0.07	0.15	4580	235	0.91	0.76	11020	1957	1966	7
									1968	10
133	0.08	0.10	4650	240	0.95	0.71	10670	1963	1967 MAINTAINS PRESSURE	11
									IN WINDFALL D-3 A	12
									1961	15
									1969	16
									1962 CONSIDERED BEYOND	19
									ECONOMIC REACH	20
25	0.18	0.30	620	95	0.93	0.57	2300	1922	1966 WESTCOAST	23
									1961	24
									1965	25
									1964 WESTCOAST AND PEACE	28
									RIVER TRANSMISSION	29
17	0.17	0.30	800	105	0.91	0.57	3240	1953	1965 WESTCOAST AND PEACE	30
									RIVER TRANSMISSION	31
23	0.17	0.30	800	105	0.91	0.57	3240	1953	1965 WESTCOAST AND PEACE	33
									RIVER TRANSMISSION	34
									1965	35
									1964	36
									1965 WESTCOAST AND PEACE	37
									RIVER TRANSMISSION	38
									1968 WESTCOAST AND PEACE	40
									RIVER TRANSMISSION	41
									1965	42
									1966	45
25	0.10	0.20	2330	160	0.83	0.69	6580	1958	1966 TCPL	46
5	0.22	0.40	820	75	0.90	0.58	2190	1963	1967 TCPL	49
									1965	50
									1965 TCPL	51
									1966 TCPL	52
23	0.20	0.30	1550	85	0.82	0.61	3170	1940	1966 TCPL	54
23	0.20	0.30	1550	85	0.83	0.64	3230	1940	1965 TCPL	55
									1967 TCPL	56
									1966 TCPL	57
14	0.08	0.25	1590	100	0.82	0.82	3190	1940	1965 TCPL	58
									1965	60
		GIP BASED ON MATERIAL BALANCE					2510	1946	1968 TCPL AND LOCAL	63
									UTILITY	64

TABLE A-1 (CONTINUED) - ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
PROVOST (CONTINUED)									
VIKING (OTHER)	35	0.75	0.05	25		25	1030	26	
VIKING ASSOC	19	0.70	0.05	13		13	1030	13	
MANNVILLE	29	0.85	0.05	24		24	1000	24	
QUIRK CREEK									
RUNDLE A	740	0.85	0.20	500		500	1110*	555	9900
RAINBOW									
SLAVE POINT	6	0.90	0.15	4		4	1100*	4	
SULPHUR POINT	35	0.85	0.15	26		26	1100*	29	
SULPHUR POINT ASSOC	3	0.85	0.15	2		2	1100*	2	
SULPHUR POINT SOLN	4	0.65	0.20	2		2	1100*	2	
MUSKEG	8	0.90	0.15	6		6	1120*	7	
MUSKEG SOLN	10	0.65	0.30	5		5	1150*	6	
KEG RIVER Q	18	0.85	0.10	14		14	1150*	16	160
KEG RIVER FFF	19	0.90	0.10	16		16	1150*	18	160
KEG RIVER (OTHER)	17	0.85	0.15	12		12	1150*	14	
KEG RIVER A ASSOC	38	0.85	0.15	28	-5	33	1200*	40	340
KEG RIVER F ASSOC	74	0.85	0.90	57		57	1200*	68	2260
KR ASSOC (OTHER)	20	0.85	0.10	15		15	1200*	18	
KEG RIVER A SOLN	130	0.75	0.20	76	2	74	1260*	93	
KEG RIVER B SOLN	91	0.45	0.20	33	1	32	1260*	40	
KEG RIVER E SOLN	19	0.65	0.15	11		11	1260*	14	
KEG RIVER F SOLN	150	0.75	0.15	97	2	95	1260*	120	
KEG RIVER O SOLN	34	0.50	0.25	13		13	1260*	16	
KEG RIVER II SOLN	20	0.75	0.25	11		11	1260*	14	
KR SOLN.(OTHER)	159	0.75	0.25	88		88	1260*	111	
RAINBOW SOUTH									
WINTERBURN	2	0.90	0.05	2		2	1060*	2	
SULPHUR POINT	33	0.85	0.10	24		24	1100*	26	
MUSKEG	15	0.85	0.20	11		11	1100*	12	
KEG RIVER	7	0.85	0.15	5		5	1150*	6	
KEG RIVER ASSOC	19	0.85	0.15	13		13	1150*	15	
KEG RIVER A SOLN	34	0.75	0.25	19		19	1200*	23	
KEG RIVER B SOLN	26	0.75	0.15	17		17	1200*	20	
KEG RIVER G SOLN	24	0.75	0.25	13		13	1200*	16	
KR SOLN (OTHER)	30	0.75	0.25	17		17	1200*	20	
REDLAND									
BELLY RIVER	1	0.65	0.05	1		1	1000	1	
VIKING	3	0.80	0.05	2		2	1000	2	
MANNVILLE	18	0.85	0.05	15	4	11	1070	12	
REDWATER									
VIKING	26	0.75	0.05	19	1	18	1040	19	
MANNVILLE	1	0.80	0.05	1	1	□ 1	1050	□ 1	
D-1	4	0.85	0.05	3	2	1	1070	1	
D-3 SOLN	240	0.60	0.65	49	13	36	1220*	44	
RED WILLOW									
VIKING	19	0.75	0.05	13		13	1020	13	
MANNVILLE	17	0.80	0.05	13		13	1100	14	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1968	2
									1967	3
										4
									1961	5
										6
										7
143	0.08	0.15	2270	120	0.75	0.75	6160	1967	1969	8
										9
										10
									1967 CONSIDERED BEYOND	11
									1967 ECONOMIC REACH	12
									1967	13
									1968	14
										15
									1967	16
									1967	17
248	0.07	0.10	2400	630	0.85	0.70	5743	1966	1968	18
396	0.05	0.20	2570	600	0.80	0.70	6050	1966	1968	19
									1967	20
										21
147	0.11	0.06	2570	655	0.82	0.78	6015	1965	1968	22
79	0.07	0.15	2480	180	0.70	0.70	5870	1966	1967	23
									1967	24
							6380	1965	1968 INJ INTO GAS CAP	25
							5970	1965	1967	26
										27
							5930	1966	1967	28
							6090	1966	1967	29
							6050	1966	1968	30
							5940	1967	1968	31
									1967	32
										33
										34
									1967 CONSIDERED BEYOND	35
									1967 ECONOMIC REACH	36
									1967	37
									1967	38
										39
									1967	40
							6370	1965	1967	41
							6460	1966	1967	42
							6390	1967	1968	43
									1968	44
										45
										46
									1966	47
									1961	48
									1966 CWNG	49
										50
										51
									1965 LOCAL UTILITY AND	52
									CIGOL	53
									1960 LOCAL UTILITY AND	54
									CIGOL	55
										56
									1967 LOCAL UTILITY AND	57
									CIGOL	58
							3210	1948	1965 LOCAL UTILITY AND	59
									CIGOL	60
										61
										62
									1969 CONSIDERED BEYOND	63
									1969 ECONOMIC REACH	64

TABLE A-1 (CONTINUED) - ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
RETLAW									
BOW ISLAND	8	0.75	0.05	6	1	5	950	5	
BASAL COLORADO	8	0.75	0.05	6		6	1020	6	
MANNVILLE B & D	27	0.90	0.10	22	7	15	1000	15	3990
MANNVILLE J	21	0.90	0.05	18	1	17	1000	17	1250
MANNVILLE K	14	0.90	0.15	11		11	1000	11	1250
MANNVILLE (OTHER)	44	0.85	0.10	32		32	1000	32	
RUNDLE	2	0.85	0.10	1		1	1010	1	
RUNDLE ASSOC	2	0.90	0.10	2		2	1010	2	
RICH									
LOWER MANNVILLE A	16	0.85	0.10	12	1	11	1100	12	3810
RICHDALE									
VIKING A	12	0.85	0.05	10		10	1010	10	6650
VIKING (OTHER)	7	0.85	0.05	6		6	1010	6	
MANNVILLE	11	0.75	0.05	9		9	1050	9	
RICINUS									
D-3 A	150	0.85	0.35	80		80	1100	88	
ROCHESTER									
VIKING	4	0.80	0.05	3		3	1000	3	
MANNVILLE	25	0.75	0.05	18		18	1000	18	
WABAMUN	6	0.90	0.05	5		5	1070	5	
ROWLEY									
BELLY RIVER	6	0.80	0.05	4		4	1000	4	
VIKING	10	0.85	0.05	8		8	1040	8	
MANNVILLE	12	0.85	0.05	10		10	1070	11	
MANNVILLE ASSOC	10	0.85	0.05	8		8	1070	9	
PEKISKO A ASSOC	47	0.90	0.10	38	4	34	1080*	37	6780
PEKISKO SOLN	8	0.65	0.25	4		4	1100*	4	
RYCROFT									
BLUESKY	7	0.80	0.05	5	3	2	1040	2	
GETHING	13	0.90	0.05	11	1	10	1040	10	
SADDLE HILLS									
CADOTTE D	37	0.70	0.05	25		25	1020	26	5380
PEACE RIVER	11	0.70	0.05	7		7	1020	7	
GETHING	5	0.80	0.05	4		4	980	4	
BELLOY A	22	0.80	0.15	15		15	1030	15	1050
SAMSON									
BLAIRMORE	8	0.85	0.05	7		7	1070*	7	
BLAIRMORE ASSOC	9	0.80	0.05	7**					
BLAIRMORE SOLN	2	0.65	0.05	1**	6**	2	1070*	2	
SARCEE									
RUNDLE A	210	0.85	0.15	150	46	104	1050*	109	3100
SARCEE WEST									
KOOTENAY 17-23-4	13	0.80	0.05	10		10	1020	10	500
SAVANNA CREEK									
RUNDLE A	340	0.85	0.30	200	32	168	1020	171	7980
SEDALIA									
VIKING A	140	0.80	0.05	100	7	93	1010*	94	
VIKING (OTHER)	3	0.80	0.05	2		2	1010	2	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1968 TCPL	2
									1965	3
7	0.22	0.30	1720	95	0.79	0.71	3570	1959	1968 TCPL	4
23	0.21	0.40	1700	95	0.81	0.71	3110	1966	1967	5
										6
8	0.29	0.15	1650	85	0.79	0.71	3550	1954	1969	7
									1968	8
									1966	9
									1966	10
										11
										12
13	0.12	0.30	1270	135	0.87	0.65	4800	1953	1961 TCPL	13
										14
										15
4	0.20	0.40	1080	90	0.87	0.60	3100	1955	1968	16
									1968	17
									1968	18
										19
										20
									1969	21
										22
										23
									1953 CONSIDERED BEYOND	24
									1953 ECONOMIC REACH	25
									1953	26
										27
										28
									1964	29
									1966	30
									1964	31
									1965	32
										33
22	0.08	0.20	1500	120	0.82	0.71	4410	1960	1963 TCPL	34
									1967	35
										36
										37
									1961 LOCAL UTILITY	38
									1961 LOCAL UTILITY	39
										40
										41
17	0.21	0.30	930	115	0.92	0.57	3640	1957	1965	42
									1965	43
									1965	44
35	0.10	0.25	2600	155	0.82	0.65	6970	1957	1965	45
										46
										47
									1968	48
									1965	49
									1965 NUL	50
										51
										52
103	0.08	0.20	3790	180	0.88	0.72	9750	1954	1964 CWNG	53
										54
										55
45	0.10	0.35	3650	225	0.95	0.67	11030	1957	1958 CONSIDERED BEYOND	56
									ECONOMIC REACH	57
										58
										59
219	0.03	0.15	2770	135	0.78	0.66	8350	1954	1966 WESTCOAST	60
										61
										62
9	0.17	0.40	930	85	0.89	0.60	2660	1954	1962 TCPL	63
									1968	64

TABLE A-1 (CONTINUED) - ESTABLISHED RESERVES OF GAS IN THE PROVINC

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
SEDALIA (CONTINUED)									
MANNVILLE	5	0.85	0.05	4		4	1010	4	
SEDGEWICK									
VIKING	3	0.75	0.05	2		2	1000	2	
BASAL MANNVILLE A	19	0.85	0.05	16		16	990	16	2310
MANNVILLE (OTHER)	10	0.85	0.05	8		8	990	8	
SEIU LAKE									
VIKING	8	0.80	0.05	6		6	1000	6	
MANNVILLE	25	0.80	0.05	20	1	19	1000	19	
SEPTEMBER LAKE									
MANNVILLE	12	0.75	0.05	8		8	1030	8	
MANNVILLE ASSOC	1	0.75	0.05	1		1	1030	1	
WABAMUN	2	0.75	0.05	1		1	940	1	
SEXSMITH									
DUNVEGAN	6	0.80	0.05	5	1	4	1000	4	
SIBBALD									
VIKING A	28	0.80	0.05	21	14	7	990	7	9870
VIKING (OTHER)	7	0.80	0.05	6		6	990	6	
BASAL COLORADO A	13	0.80	0.05	10		10	990	10	4210
BANFF	1	0.80	0.05	1		1	1050	1	
SIMONETTE									
CADOTTE	9	0.90	0.05	7		7	1050	7	
CADOMIN A	13	0.85	0.05	10		10	1060	11	1500
WABAMUN A	34	0.85	0.35	19		19	1070	20	250
WABAMUN B	26	0.85	0.35	14		14	1070	15	250
WABAMUN (OTHER)	13	0.85	0.35	7		7	1070	7	
D-3 SOLN	270	0.55	0.40	89	2	87	1020	89	
SMITH COULEE									
BOW ISLAND A	32	0.85	0.05	26	23	3	930	3	
ST. ALBERT-BIG LAKE									
VIKING	1	0.80	0.05	1		1	1070*	1	
VIKING ASSOC	2	0.80	0.05	2		2	1070*	2	
OSTRACOD A	98	0.85	0.05	80	65	15	1070*	16	
BASAL QUARTZ B	26	0.85	0.05	21		21	1070*	22	1060
MANNVILLE (OTHER)	10	0.85	0.05	8		8	1070*	9	
STANDARD									
VIKING A	26	0.80	0.05	20		20	1000	20	5550
STEEP CREEK									
GETHING	6	0.85	0.05	5		5	1020	5	
TRIASSIC	9	0.85	0.10	7		7	1030	7	
PERMO-PENN 26-66-7	17	0.90	0.20	12		12	1030	12	1100
STETTLER									
VIKING	3	0.80	0.05	2		2	1020	2	
D-2 SOLN	21	0.30	0.90	1		1	1130	1	
D-3 SOLN	14	0.55	0.95	1		1	1140	1	
STOLBERG									
RUNDLE A	86	0.90	0.10	70		70	1040	73	1480
ST. PAUL									
MANNVILLE	5	0.75	0.10	4	4	□ 1	1000	□ 1	

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1968	2
										3
										4
									1956	5
11	0.30	0.20	980	95	0.86	0.64	2940	1954	1968	6
									1956	7
										8
										9
									1966	10
									1963 TCPL	11
										12
										13
									1966 CONSIDERED BEYOND	14
									1966 ECONOMIC REACH	15
									1966	16
										17
										18
									1967 LOCAL UTILITY	19
										20
										21
6	0.22	0.30	1000	90	0.89	0.58	2530	1951	1966 TCPL	22
									1960	23
8	0.15	0.30	1110	90	0.87	0.61	2700	1953	1960	24
									1966	25
										26
										27
									1957	28
17	0.09	0.35	2970	165	0.85	0.66	8110	1960	1968	29
154	0.08	0.15	4950	220	0.87	0.81	11240	1959	1966	30
116	0.08	0.15	4870	220	0.87	0.81	11120	1960	1966	31
										32
									1967	33
							11580	1958	1966 CANADIAN UTILITIES	34
										35
										36
		GIP BASED ON MATERIAL BALANCE					2050	1948	1967 CMG	37
										38
										39
									1965	40
									1957	41
		GIP BASED ON MATERIAL BALANCE					3710	1952	1962 CIGOL	42
33	0.20	0.25	1360	120	0.85	0.67	3800	1952	1964	43
										44
									1964	45
										46
										47
8	0.20	0.30	1290	85	0.84	0.63	4180	1956	1963	48
										49
										50
									1961 CONSIDERED BEYOND	51
									1961 ECONOMIC REACH	52
35	0.06	0.30	4350	240	0.91	0.66	10470	1956	1961	53
										54
										55
									1963 CWNG	56
									1966 CWNG	57
									1966 CWNG	58
										59
										60
122	0.05	0.20	5100	200	0.99	0.64	12730	1957	1958	61
										62
										63
									1966 LOCAL UTILITY	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
STRACHAN									
D-3 A	2060	0.85	0.20	1400		1400	1100	1540	5150
STRATHMORE									
BELLY RIVER	14	0.80	0.05	11	4	7	1000	7	
VIKING	9	0.80	0.05	7		7	1000	7	
RUNDLE	2	0.80	0.05	1		1	1000	1	
STROME									
MANNVILLE	2	0.90	0.05	1		1	1030	1	
STURGEON LAKE									
GETHING	13	0.85	0.05	10		10	1000	10	
GILWOOD	1	0.85	0.15	1		1	1000	1	
STURGEON LAKE SOUTH									
GETHING 19-69-25	21	0.85	0.10	16		16	1000	16	1100
GETHING (OTHER)	23	0.85	0.05	19		19	1000	19	
TRIASSIC ASSOC	3	0.85	0.10	2		2	1180	2	
TRIASSIC SOLN	13	0.65	0.70	3		3	1180	4	
PERMO-PENN	11	0.85	0.05	9		9	1030	9	
D-1	4	0.90	0.20	3	1	2	1070	2	
D-3 ASSOC	10	0.90	0.25	7		7	1080	8	
D-3 SOLN	270	0.55	0.45	83	16	67	1080	72	
SUNDRE									
MANNVILLE	6	0.85	0.10	4		4	1020	4	
MANNVILLE ASSOC	10	0.90	0.10	8		8	1020	8	
RUNDLE A ASSOC	21	0.85	0.15	15		15	1060*	16	1660
RUNDLE A SOLN	59	0.40	0.50	12		12	1060*	13	
RUNDLE SOLN (OTHER)	13	0.60	0.50	4		4	1060*	4	
SUNNYNOOK									
VIKING	1	0.75	0.05	1		1	1020	1	
MANNVILLE	16	0.85	0.05	13		13	1020	13	
SWALWELL									
VIKING	7	0.80	0.05	5		5	1000	5	
PEKISKO A ASSOC	43	0.85	0.05	35		35	1100	39	4000
SWAN HILLS									
GETHING	2	0.90	0.05	1		1	1050	1	
BHL LK A & B SOLN	1090	0.45	0.35	320	23	297	1200*	356	
SWAN HILLS SOUTH									
BHL LK SOLN	570	0.45	0.30	180	16	164	1120*	184	
SYLVAN LAKE									
VIKING	4	0.85	0.05	3		3	1010*	3	
GLAUCONITIC A	210	0.85	0.10	160	34	126	1100*	139	6290
OSTRACOD B	27	0.85	0.10	21	2	19	1100*	21	2230
LOWER MANNVILLE A	34	0.85	0.10	26	7	19	1100*	21	2830
LOWER MANNVILLE C	22	0.85	0.10	17	9	8	1100*	9	2260
LOWER MANNVILLE D	28	0.85	0.10	21	3	18	1100*	20	2620
MANNVILLE (OTHER)	46	0.85	0.10	35	1	34	1100*	37	
MANNVILLE ASSOC	2	0.80	0.10	2		2	1100*	2	
JURASSIC	25	0.85	0.10	19	1	18	1020*	18	
JURASSIC A ASSOC	40	0.80	0.10	29		29	1020*	30	3010
JUR ASSOC (OTHER)	3	0.85	0.10	2		2	1020*	2	
JURASSIC SOLN	23	0.60	0.45	8		8	1100*	9	

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11	12	13	14	15	16	17	18	19	20
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS
290	0.11	0.10	7150	250	1.14	0.74	9430	1967	1969
									1963 CWNG
									1963
									1963
									1966 LOCAL UTILITY
									1967 CONSIDERED BEYOND
									1967 ECONOMIC REACH
34	0.15	0.30	1700	115	0.86	0.61	5200	1954	1967
									1967
									1967
									1965
									1968
									1967 CANADIAN UTILITIES
									1961
							8850	1953	1965 CANADIAN UTILITIES
									1964
									1966
16	0.10	0.20	3670	200	0.90	0.65	9050	1955	1964
							9050	1955	1965
									1965
									1966
									1966 TCPL
									1966
32	0.08	0.25	1790	145	0.83	0.69	5300	1963	1966
									1962
							8300	1957	1966 NUL
							7450	1959	1966 NUL
									1966
31	0.13	0.30	2420	155	0.79	0.75	7100	1953	1964 TCPL
13	0.17	0.30	2650	160	0.82	0.73	7790	1963	1964 TCPL
18	0.13	0.30	2470	160	0.82	0.73	7170	1955	1964 TCPL
13	0.15	0.30	2450	160	0.80	0.72	7130	1953	1964 TCPL
16	0.13	0.30	2410	155	0.81	0.73	6890	1953	1964 TCPL
									1964 TCPL
									1964
									1965
21	0.12	0.30	2500	160	0.83	0.69	7410	1962	1965
									1966
									1965

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
SYLVAN LAKE (CONTINUED)									
ELKTON-SHUNDA A	25	0.85	0.10	20	9	11	1100*	12	3380
SHUNDA B	24	0.85	0.10	18		18	1100*	20	1790
PEKISKO L	76	0.80	0.10	55	2	53	1100*	58	3220
RUNDLE (OTHER)	29	0.85	0.10	23		23	1100*	25	
RUNDLE ASSOC	17	0.80	0.10	12		12	1100*	13	
RUNDLE SOLN	38	0.60	0.35	15		15	1200*	18	
D-3 A ASSOC	35	0.80	0.10	25**					1800
D-3 SOLN	15	0.65	0.45	5**	3**	27	1020*	28	
TABER SOUTH									
BOW ISLAND A	17	0.70	0.05	11		11	1000	11	12410
BOW ISLAND (OTHER)	11	0.80	0.05	8		8	1000	8	
TANGENT									
PEACE RIVER	12	0.75	0.05	6		6	1010	6	
GETHING	42	0.85	0.05	34		34	1000	34	
TRIASSIC	25	0.85	0.05	20		20	1180	24	
TELFORDVILLE									
MISSISSIPPIAN	11	0.85	0.10	9		9	1110	10	
WABAMUN	7	0.85	0.15	4		4	1090	4	
THORHILD									
MANNVILLE A	12	0.85	0.05	10		10	1000	10	2550
MANNVILLE (OTHER)	1	0.85	0.05	1		1	1000	1	
THREE HILLS CREEK									
BELLY RIVER	8	0.85	0.05	7		7	970	7	
VIKING	8	0.80	0.05	6		6	1000	6	
PEKISKO	190	0.85	0.05	150	23	127	1120*	142	43770
LEDUC	11	0.75	0.15	7		7	1100	8	
TROCHU									
MANNVILLE	14	0.75	0.10	10		10	1030	10	
TURIN									
BOW ISLAND	14	0.80	0.05	10		10	970	10	
MANNVILLE	17	0.90	0.15	13		13	1020	13	
MANNVILLE ASSOC	10	0.85	0.15	7		7	1020	7	
TURNER VALLEY									
RUNDLE ASSOC	1570	0.90	0.70	410	297	113	1110*	125	
RUNDLE SOLN	1400	0.55	0.55	350	285	65	1110*	72	
TWEEDIE									
VIKING	13	0.80	0.05	10	1	9	1000	9	
GRAND RAPIDS A	17	0.80	0.05	13	1	12	1040	12	10430
GLAUCONITIC A	18	0.80	0.05	14	2	12	1040	12	15650
MCMURRAY A	16	0.80	0.05	12		12	1040	12	17760
MANNVILLE (OTHER)	7	0.80	0.05	5		5	1040	5	
TWINING NORTH									
MANNVILLE	6	0.80	0.05	5		5	1100	6	
RUNDLE	1	0.80	0.05	1		1	1110	1	
RUNDLE ASSOC	37	0.80	0.05	28		28	1110	31	4340

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11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	Line
17	0.08	0.25	2470	160	0.79	0.75	7140	1955	1965 TCPL	2
23	0.10	0.25	2500	160	0.79	0.75	7210	1953	1964	3
36	0.11	0.25	2380	140	0.79	0.74	6920	1963	1966 TCPL	5
									1964	6
									1964	7
									1965	8
41	0.06	0.20	3490	210	0.87	0.74	9400	1961	1964 TCPL	9
									1964 TCPL	11
6	0.20	0.30	540	80	0.94	0.60	2300	1963	1965 CONSIDERED BEYOND	14
									1961 ECONOMIC REACH	15
									1968	18
									1968	19
									1968	20
									1957	23
									1966	24
12	0.25	0.30	740	85	0.91	0.60	2570	1963	1966 LOCAL UTILITY	27
									1964	28
									1963	31
									1963	32
27	0.05	0.35	1720	150	0.85	0.70	5770	1953	1968 TCPL	33
									1963	34
									1968	37
									1968	40
									1968	41
									1968	42
							6000	1936	1953 CWNG AND LOCAL	45
							8390	1936	1953 UTILITY	46
									1968 GREAT CANADIAN OIL	49
									SANDS LIMITED	50
6	0.38	0.30	320	55	0.95	0.56	900	1961	1968 GREAT CANADIAN OIL	51
									SANDS LIMITED	52
7	0.28	0.50	360	60	0.94	0.57	1390	1961	1968 GREAT CANADIAN OIL	54
									SANDS LIMITED	55
6	0.27	0.50	360	60	0.95	0.57	1430	1961	1968 GREAT CANADIAN OIL	56
									SANDS LIMITED	57
									1968 GREAT CANADIAN OIL	58
									SANDS LIMITED	59
									1964	62
									1964	63
36	0.07	0.30	1660	145	0.85	0.68	5370	1961	1964	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
TWINING NORTH (CONTINUED)									
RUNDLE ASSOC (OTHER)	1	0.80	0.05	1		1	1110	1	
RUNDLE SOLN	15	0.60	0.15	8		8	1110	9	
TWO CREEK									
TRIASSIC 11-63-16	12	0.90	0.05	10		10	1090	11	1100
USONA									
MANNVILLE 11-45-27	12	0.90	0.05	10		10	1110	11	470
VERGER									
BOW ISLAND	3	0.75	0.05	2		2	1100	2	
BASAL COLORADO	11	0.80	0.05	9	3	6	1010	6	
MANNVILLE	39	0.75	0.05	28	2	26	1050	27	
PEKISKO	2	0.85	0.05	2		2	1070	2	
VIKING-KINSELLA									
VIKING	960	0.85	0.05	770	422	348	1000	348	40800
WAINWRIGHT	41	0.80	0.05	31	4	27	1000	27	6750
MANNVILLE (OTHER)	40	0.80	0.05	30	15	15	1000	15	
D-2	18	0.80	0.05	14	5	9	990*	9	
D-3	1	0.85	0.05	1	1	¤ 1	990*	¤ 1	
VIRGINIA HILLS									
MANNVILLE	9	0.90	0.05	8		8	1040	8	
BELLOY A ASSOC	20	0.85	0.10	15		15	1060	16	3200
BHL LK SOLN	220	0.40	0.40	54	7	47	1070*	50	
SLAVE POINT	4	0.80	0.20	2		2	1070	2	
VULCAN									
BASAL MANNVILLE A	15	0.85	0.15	11	1	10	1050	11	2320
MANNVILLE (OTHER)	5	0.85	0.15	4		4	1050	4	
TURNER VALLEY A	19	0.80	0.20	13	1	12	1050	13	2440
TV (OTHER)	4	0.80	0.20	2		2	1050	2	
WAINWRIGHT									
VIKING	5	0.80	0.05	4		4	980	4	
MANNVILLE	18	0.85	0.05	14		14	940	13	
MANNVILLE ASSOC	8	0.75	0.05	5		5	940	5	
WASKAHIGAN									
CARDIUM	4	0.80	0.05	3		3	1060	3	
DUNVEGAN A	125	0.80	0.05	90		90	1110	100	26980
CADOTTE	5	0.85	0.05	4		4	1070	4	
WATERTON									
RUNDLE A	54	0.80	0.30	32	5	27	1040*	28	
RUNDLE C	350	0.75	0.45	150	11	139	1040*	145	13390
RUNDLE D & E	470	0.80	0.50	190	46	144	1040*	150	
RUNDLE (OTHER)	7	0.85	0.30	4		4	1040*	4	
RUNDLE-WABAMUN A	3080	0.85	0.35	1700	149	1551	1020	1582	
WABAMUN B	36	0.80	0.20	25	11	14	1020	14	
WABAMUN 31-6-3	40	0.85	0.15	29		29	1020	30	2000
WATTS									
VIKING	3	0.80	0.05	2	2	¤ 1	1030*	¤ 1	
MISSISSIPPIAN	1	0.80	0.05	1		1	1070	1	

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11 AVERAGE PAY THICKNESS FEET	12 POROSITY FRACTION	13 LIQUID SATURATION FRACTION	14 INITIAL PRESSURE PSIA	15 RESERVOIR TEMPERATURE °F	16 COMPRESS-IBILITY FACTOR FRACTION	17 RAW GAS SPECIFIC GRAVITY	18 AVERAGE WELL DEPTH FEET	19 DISCOVERY YEAR	20 DATE LAST REVIEWED, DISPOSITION AND REMARKS
									1964
									1965
12	0.20	0.30	2200	170	0.88	0.66	6590	1956	1956 CONSIDERED BEYOND ECONOMIC REACH
32	0.22	0.30	1660	140	0.84	0.71	5110	1954	1955 CONSIDERED BEYOND ECONOMIC REACH
									1964 TCPL
									1965 TCPL
									1968 TCPL
									1964 TCPL
5	0.23	0.20	810	75	0.90	0.60	2080	1914	1966 NUL AND LOCAL UTILITY
13	0.26	0.25	740	85	0.91	0.59	2330	1951	1966 NUL
									1966 NUL
									1966 NUL
									1961 NUL
									1962
10	0.15	0.30	1950	155	0.86	0.69	6150	1961	1962
							9290	1957	1966 NUL
									1962
9	0.15	0.35	2320	125	0.85	0.76	5880	1956	1968 TCPL
									1968
13	0.10	0.40	2440	145	0.82	0.76	5940	1960	1966 TCPL
									1966
									1959 LOCAL UTILITY
									1960 LOCAL UTILITY
									1968
									1967
12	0.16	0.45	1490	145	0.85	0.67	5080	1959	1969
									1967
		GIP BASED ON MATERIAL BALANCE					9406	1960	1968 A&S
56	0.05	0.25	5200	190	1.00	0.94	11600	1957	1968 A&S
		GIP BASED ON MATERIAL BALANCE					10700	1957	1968 A&S
									1964 A&S
		GIP BASED ON MATERIAL BALANCE					10350	1959	1968
		GIP BASED ON MATERIAL BALANCE					13400	1958	1968 A&S
58	0.05	0.20	4020	205	0.91	0.66	12170	1964	1966
									1960 LOCAL UTILITY
									1955

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
WAYNE-ROSEDALE									
BELLY RIVER	8	0.80	0.05	6	1	5	1000	5	
VIKING A	160	0.85	0.05	130	29	101	1090*	110	49870
VIKING B	37	0.80	0.05	28	4	24	1090*	26	9940
VIKING (OTHER)	29	0.85	0.05	23	1	22	1090*	24	
GLAUCONITIC A	150	0.85	0.05	120	28	92	1120	103	19440
MANNVILLE (OTHER)	64	0.85	0.05	52	12	40	1120	45	
MANNVILLE ASSOC	3	0.85	0.05	2	2	□ 1	1120	□ 1	
WEST DRUMHELLER									
MANNVILLE	4	0.85	0.05	3		3	1100	3	
RUNDLE	1	0.80	0.05	1		1	1040	1	
D-2 ASSOC	5	0.90	0.15	4		4	1090	4	
WESTEROSE									
VIKING	3	0.80	0.05	2		2	1000	2	
MANNVILLE	7	0.80	0.05	5		5	1020	5	
NISKU	2	0.90	0.05	1		1	1050	1	
D-3 ASSOC	130	0.90	0.20	90	-7	97	1050*	102	1220
D-3 SOLN	150	0.70	0.20	83	10	73	1050*	77	
WESTEROSE SOUTH									
WABAMUN	8	0.90	0.25	6		6	1090	7	
D-3 A	1850	0.90	0.20	1350	415	935	1060*	991	11790
WESTLOCK									
VIKING	320	0.80	0.05	250	67	183	1060	194	75270
VIKING (OTHER)	8	0.80	0.05	6		6	1060	6	
MANNVILLE	4	0.85	0.05	3		3	1100*	3	
WEST PRAIRIE									
CADOTTE 18-72-17	17	0.90	0.05	15		15	1040	16	1100
BLUESKY	6	0.90	0.05	5		5	990	5	
WHISKEY									
RUNDLE A	157	0.85	0.25	100		100	1110*	111	
WHITECOURT									
BELLY RIVER	2	0.85	0.05	1		1	1000	1	
VIKING	1	0.75	0.05	1		1	1050	1	
MANNVILLE	14	0.80	0.10	10		10	1050	11	
JURASSIC E	55	0.85	0.10	42		42	1070	45	5130
JURASSIC	26	0.80	0.10	18		18	1070	19	
PEKISKO C	13	0.85	0.10	10		10	1130	11	830
PEKISKO	35	0.85	0.10	26		26	1130	29	
WHITELAW									
BLUESKY	2	0.80	0.05	1		1	1020	1	
BLUESKY A-GETHING A	14	0.85	0.05	12	5	7	1020	7	2600
GETHING B	13	0.85	0.05	11	1	10	1020	10	3720
TRIASSIC A	21	0.85	0.05	16		16	1090	17	5680
TRIASSIC (OTHER)	10	0.90	0.05	9		9	1090	10	
WILDCAT HILLS									
RUNDLE A	900	0.80	0.17	600	146	454	1050*	477	9630
WILDHORSE CREEK									
RUNDLE A	160	0.85	0.20	110		110	1010	111	1960

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1961 CWNG	2
6	0.20	0.30	1170	110	0.87	0.64	3710	1953	1965 TCPL	3
9	0.16	0.30	1170	110	0.87	0.64	3950	1954	1963 TCPL	4
									1966 CWNG & LOCAL UTILITY	5
										6
13	0.18	0.30	1430	115	0.82	0.66	4400	1953	1966 CWNG & LOCAL UTILITY	7
									1961 CWNG & LOCAL UTILITY	8
									1962	9
										10
										11
									1954	12
									1956	13
									1968	14
										15
										16
									1961	17
									1953	18
									1959	19
200	0.08	0.15	2520	180	0.83	0.71	6990	1952	1959	20
										21
							7230	1952	1966 TCPL	22
										23
										24
									1961	25
249	0.09	0.10	2750	180	0.81	0.81	7640	1953	1969 TCPL	26
										27
										28
13	0.19	0.35	840	95	0.90	0.58	2600	1949	1964 CIGOL & LOCAL	29
									UTILITY	30
									1964	31
									1962	32
										33
										34
35	0.20	0.30	990	85	0.87	0.68	2580	1956	1956 CONSIDERED BEYOND	35
									1956 ECONOMIC REACH	36
										37
										38
									1969	39
										40
										41
									1963	42
									1958	43
									1963	44
23	0.18	0.50	1850	140	0.84	0.64	5070	1962	1969	45
										46
									1968	47
48	0.09	0.45	1840	145	0.85	0.64	5080	1968	1968	48
									1968	49
										50
										51
									1961 LOCAL UTILITY	52
14	0.21	0.45	1110	75	0.87	0.57	2900	1950	1966 LOCAL UTILITY	53
6	0.20	0.25	1150	75	0.86	0.57	2180	1959	1966 LOCAL UTILITY	54
5	0.21	0.30	1430	105	0.82	0.58	3240	1951	1966	55
										56
									1957	57
										58
										59
198	0.05	0.15	3910	185	0.91	0.70	9880	1958	1967 A&S	60
										61
										62
123	0.08	0.15	3200	140	0.85	0.68	7380	1960	1968	63

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
WILDMERE									
MANNVILLE	37	0.80	0.05	28	10	18	960*	17	
WILDUNN CREEK									
VIKING A	19	0.60	0.05	11		11	1010	11	8810
VIKING B	16	0.70	0.05	11	4	7	1010	7	4080
WILLESDEN GREEN									
BELLY RIVER E	34	0.85	0.10	26		26	1000	26	3790
BELLY RIVER (OTHER)	23	0.80	0.05	17		17	1000	17	
CARDIUM	12	0.80	0.05	9		9	1040*	9	
CARDIUM SOLN	440	0.40	0.55	83	7	76	1040*	79	
MANNVILLE	29	0.85	0.10	22		22	1100	24	
MANNVILLE ASSOC	2	0.75	0.15	1		1	1100	1	
JURASSIC	4	0.75	0.05	3		3	1080	3	
MISSISSIPPIAN	3	0.80	0.05	2		2	1100	2	
WILLINGDON									
VIKING	3	0.75	0.05	2		2	980	2	
MANNVILLE	16	0.75	0.05	12	3	9	990	9	
D-3	12	0.80	0.05	9	8	1	1000*	1	
WILSON CREEK									
PEKISKO A	51	0.85	0.10	39	3	36	1120*	40	7900
BANFF A	15	0.85	0.15	11		11	1120*	12	1100
WIMBORNE									
VIKING	2	0.75	0.05	1		1	1020	1	
RUNDLE	2	0.90	0.10	1		1	1100	1	
D-2	1	0.85	0.15	1		1	1160	1	
D-2 ASSOC	2	0.80	0.15	2		2	1160	2	
D-3 A ASSOC	360	0.70	0.25	190**					15080
D-3 A SOLN	110	0.95	0.25	3**	47**	146	1000*	146	
WINDFALL									
VIKING A	17	0.75	0.05	12		12	1030	12	8990
RUNDLE	5	0.85	0.05	4	2	2	1040	2	
D-3	3	0.90	0.35	2		2	1080*	2	
D-3 A ASSOC	710	0.80	0.30	400**					11600
D-3 A SOLN	230	0.70	0.35	110**	64**	446	1080*	482	
WINNIFRED									
BOW ISLAND A	19	0.85	0.05	16		16	1000	16	22560
BOW ISLAND (OTHER)	1	0.80	0.05	1		1	1000	1	
WINTERING HILLS									
BELLY RIVER	2	0.75	0.05	1		1	1000	1	
VIKING D	12	0.90	0.05	10		10	1010	10	1100
VIKING (OTHER)	18	0.85	0.05	14	2	12	1010	12	
VIKING ASSOC	9	0.75	0.05	7		7	1010	7	
MANNVILLE	26	0.80	0.10	20		20	1090	22	
LOWER MANN E ASSOC	17	0.75	0.10	12	1	11	1090	12	2850
MANN ASSOC (OTHER)	5	0.80	0.05	4		4	1090	4	
RUNDLE	2	0.80	0.05	1		1	1090	1	
WIZARD LAKE									
BELLY RIVER	2	0.75	0.05	1		1	1050	1	
VIKING	1	0.85	0.05	1		1	1070	1	
MANNVILLE	3	0.85	0.05	2	2	□ 1	1120	□ 1	

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESSIBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1953 NUL	2
										3
										4
4	0.25	0.40	1110	90	0.86	0.61	3030	1952	1967	5
7	0.25	0.40	1130	90	0.87	0.59	3090	1952	1967 TCPL	6
										7
										8
16	0.15	0.25	1600	145	0.82	0.70	5050	1967	1967	9
									1965	10
									1961	11
							6190	1954	1967 A&S	12
										13
									1962	14
									1965	15
									1956	16
									1956	17
										18
										19
									1961 WESTERN MINERALS AND	20
									1961 LOCAL UTILITY	21
									1965 WESTERN MINERALS	22
										23
										24
19	0.06	0.25	2800	190	0.87	0.68	7040	1960	1966 A&S	25
37	0.06	0.25	2800	195	0.87	0.70	7290	1961	1966	26
										27
										28
									1956	29
									1961	30
									1959	31
									1959	32
										33
41	0.08	0.10	3010	175	0.83	0.78	7480	1954	1969 TCPL	34
							7490	1956	1969 TCPL	35
										36
										37
6	0.08	0.20	1570	145	0.87	0.63	5140	1955	1963	38
									1961 A&S	39
									1961	40
116	0.06	0.15	3790	220	0.83	0.81	9050	1955	1967 A&S PRESSURE MAIN-	41
										42
							9100	1957	1966 A&S TAINED WITH PINE	43
									CK & PINE NW GAS	44
										45
										46
4	0.20	0.40	730	85	0.92	0.59	2080	1963	1966 LOCAL UTILITY	47
									1969	48
										49
										50
									1963	51
19	0.20	0.30	1280	90	0.86	0.65	3130	1955	1965	52
									1966 TCPL	53
									1965	54
										55
									1968	56
13	0.17	0.35	1410	105	0.80	0.70	4110	1966	1968	57
									1966	58
									1963	59
										60
										61
									1966	62
									1960	63
									1959 NUL	64

TABLE A-1 (CONTINUED)-ESTABLISHED RESERVES OF GAS IN THE PROVINCE

1	2	3	4	5	6	7	8	9	10
POOL OR ZONE	INITIAL GAS IN PLACE BCF	POOL RECOVERY FRACTION	SURFACE LOSS FRACTION	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED MAY 31/69 BCF	REMAINING MARKETABLE GAS MAY 31/69 BCF	GROSS HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS AT 1000 BTU BCF	AREA ACRES
WIZARD LAKE (CONTINUED)									
MANNVILLE ASSOC	11	0.80	0.15	8	8	□ 1	1120	□ 1	
D-2 ASSOC	1	0.85	0.20	1		1	1180	1	
D-3 A SOLN	230	0.65	0.25	110	24	86	1250	108	
WOKING									
PEACE RIVER	5	0.90	0.05	4		4	1040	4	
SPIRIT RIVER	3	0.80	0.05	2		2	1040	2	
BLUESKY	4	0.80	0.05	3	1	2	1040	2	
PERMO-PENN	2	0.80	0.05	2		2	1060	2	
KISKATINAW	3	0.75	0.05	2		2	1070	2	
WOOD RIVER									
MANNVILLE	31	0.85	0.10	24	10	14	1100	15	
WORSLEY									
D-3 A	40	0.85	0.05	32	18	14	950*	13	3380
D-3 B	90	0.85	0.05	72	17	55	950*	52	3720
D-3 D	39	0.85	0.10	30	21	9	950*	9	1000
D-3 E	16	0.85	0.05	13	3	10	950*	10	500
D-3 G	65	0.85	0.05	53	20	33	950*	31	3700
D-3 (OTHER)	4	0.85	0.05	3	1	2	950*	2	
D-3 ASSOC	1	0.80	0.05	1		1	950*	1	
YEKAU LAKE									
VIKING	8	0.80	0.02	7	2	5	1070	5	
ZAMA									
SLAVE POINT	73	0.90	0.10	60		60	1050*	63	
SULPHUR POINT	220	0.85	0.15	160		160	1050*	168	
SULPHUR POINT ASSOC	5	0.85	0.15	3		3	1050*	3	
SULPHUR POINT SOLN	6	0.70	0.30	3		3	1100*	3	
MUSKEG SOLN	26	0.70	0.25	13		13	1100*	14	
KEG RIVER	14	0.90	0.20	10		10	1150*	12	
KEG RIVER ASSOC	6	0.85	0.55	3		3	1150*	3	
KEG RIVER SOLN	220	0.70	0.25	110		110	1200*	132	
SUB TOTAL				52016	8887	43129		45489	
OTHER RESERVES									
LESS THAN 10 BCF				767		767		805	
CONFIDENTIAL POOLS				444		444		466	
TOTAL RESERVES MAY 31,1969				53227	8887	44340		46760	
TOTAL RESERVES WITHIN ECONOMIC REACH				50604	8887	41717		43892	
TOTAL RESERVES BEYOND ECONOMIC REACH				2623		2623		2868	

OF ALBERTA, MAY 31, 1969 (14.65 PSIA AND 60°F)

11	12	13	14	15	16	17	18	19	20	
AVERAGE PAY THICKNESS FEET	POROSITY FRACTION	LIQUID SATURATION FRACTION	INITIAL PRESSURE PSIA	RESERVOIR TEMPERATURE °F	COMPRESS-IBILITY FACTOR FRACTION	RAW GAS SPECIFIC GRAVITY	AVERAGE WELL DEPTH FEET	DISCOVERY YEAR	DATE LAST REVIEWED, DISPOSITION AND REMARKS	
										1
									1959 NUL	2
										3
									1968	4
							6460	1951	1966 NUL	5
										6
										7
									1961	8
									1961	9
									1961 LOCAL UTILITY	10
									1961	11
										12
									1961	13
										14
										15
									1961 TCPL	16
										17
										18
28	0.06	0.20	3310	185	0.90	0.68	7420	1960	1966 WESTCOAST	19
50	0.07	0.20	3240	180	0.90	0.65	7240	1960	1966 WESTCOAST	20
60	0.10	0.20	3090	180	0.89	0.73	7660	1961	1966 WESTCOAST	21
42	0.11	0.20	3060	170	0.91	0.67	7030	1966	1966 WESTCOAST	22
										23
42	0.06	0.20	3300	180	0.91	0.64	7280	1959	1966 WESTCOAST	24
									1966 WESTCOAST	25
									1965	26
										27
										28
									1969 INJECTED INTO LEDUC-	29
									WOODBEND	30
										31
										32
									1967 CONSIDERED BEYOND	33
									1967 ECONOMIC REACH	34
									1967	35
									1968	36
										37
									1968	38
									1967	39
									1967	40
									1968	41
										42
										43
										44
										45
										46
										47
										48
										49
										50
										51
										52
										53
										54
										55
										56
										57

APPENDIX B

THE GROWTH TREND OF RESERVES OF GAS IN ALBERTA AND THE FUTURE RESERVES TO BE CONSIDERED

The reserves considered in this section in determining the trends in the growth of reserves are the initial marketable reserves without adjustment for heating value.

Growth of Reserves

The Board in the report and decision respecting the procedures followed in determining gas surplus to the needs of the Province, OGCB 69-D[1], stated that in future it would review the growth rate over the most recent 10-year period to determine the amount of future reserve growth to be included in calculating the future surplus. Accordingly, it has done so in this report.

(1) Views of Consolidated

Consolidated did not present a detailed study of the trends in the growth of gas reserves in the Province. It estimated the initial marketable gas reserves as of April 30, 1969, to be 44.7 trillion cubic feet based partly on additional data obtained between April 30 and June 30, 1969. The reserve estimate for the Province was made by adjusting the Board's 1968 estimates where they differed significantly from Consolidated's. The differences were principally due to different geological interpretations of the pools and new information resulting from additional drilling which has occurred since the estimates were made.

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(1) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October 1969.

Consolidated determined the average growth rate over the 18-year period prior to April 30, 1969, to be 2.5 trillion cubic feet per year and proposed that this growth rate be used in determining the future reserves to be considered in the calculation of surplus.

(2) Views of the Board

The Board, in OGCB Report 69-18[(2)] reviewed in detail the long term trend in the growth of initial marketable gas reserves in the Province to December 31, 1968, and concluded that the long term growth rate was 2.5 trillion cubic feet per year. The long term growth of initial marketable gas reserves due to new discoveries and to appreciation of previous discoveries has continued to average some 2.5 trillion cubic feet per year determined on the basis used in the Board's annual reports on the reserves of crude oil, gas, natural gas liquids, and sulphur.

The Board estimated the initial marketable gas reserves as of May 31, 1969, to be some 53.2 trillion cubic feet as shown in Appendix A. At September 30, 1959,[(3)] the Board estimated the initial marketable gas reserves to be 28.0 trillion cubic feet. The initial marketable reserves have thus increased by 25.2 trillion cubic feet during the period or at the rate of 2.6 trillion cubic feet per year. Using the initial marketable

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(2) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur. Province of Alberta. December 31, 1968.

(3) Report with Respect to the Applications under The Gas Resources Preservation Act, 1956, of Alberta and Southern Gas Co. Ltd., Saskatchewan Power Corporation, Trans-Canada Pipe Lines Limited and Westcoast Transmission Company Limited. December, 1959.

gas reserves in OGCB Report 64-8[4] as 36.7 trillion cubic feet at December 31, 1963 and in OGCB Report 67-18[5] as 44.4 trillion cubic feet at December 31, 1966, the annual growth rates over the last five years and over the last two years have averaged 3.0 trillion cubic feet and 3.6 trillion cubic feet respectively. Having regard for these numbers and its policy, the Board considers it appropriate to adopt an average growth rate of 2.6 trillion cubic feet per year in estimating the growth of initial gas reserves over the next four or five years.

Ultimate Reserves

Neither Consolidated nor any of the interveners submitted new evidence respecting the ultimate reserves of the Province. However, the Alberta Division of the Canadian Petroleum Association included an estimate of 120 trillion cubic feet for the ultimate reserves of the Province along with supporting data in its submission to the hearing of June 17, 1969 reported on in report OGCB 69-D. The Canadian Petroleum Association's estimate of the ultimate reserves is close to that of the Board and having in mind the Board's wish to be conservative in this regard the Board as it did in OGCB Report 69-F[6] will continue to use 100 trillion cubic feet as its estimate of the ultimate reserves

(4) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur. Province of Alberta. December 31, 1963.

(5) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur. Province of Alberta. December 31, 1966.

(6) In the Matter of an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. November, 1969.

for the present. It plans to consider this matter more fully in its 1969 year-end report on the reserves of crude oil, gas, natural gas liquids and sulphur of the Province.

<u>Future Reserves to be Considered</u>

(1) Views of Consolidated

The Board decision, respecting the application of the Alberta Division of the Canadian Petroleum Association, considered at the hearing which began June 17, 1969, for reconsideration of the policies and procedures of the Board for considering applications under The Gas Resources Preservation Act, 1956, was not issued until after the hearing of the Consolidated application. However, Consolidated stated it strongly supported the views of the Alberta Division of the Canadian Petroleum Association that additional years of growth of gas reserves should be used in the determination of the volumes of gas that may be surplus to the long term needs of Alberta and the current permit commitments. It urged the Board to adopt the formula advanced by the Canadian Petroleum Association respecting the growth of gas reserves that should be used in the calculation of the future surplus.

(2) Views of the Board

The Board has applied the new policy described in report OGCB 69-D in determining the future reserves to be considered. In the report the Board adopted a method whereby the future growth rate of gas reserves is projected principally on the basis of the growth experienced during the previous 10 years and the number of years of growth to be considered is determined by the following

formula:

$$T_G = \frac{R_{POT} - R_{EST}}{10}$$

where T_G = Years of growth of gas reserves

R_{POT} = Potential initial marketable reserves of the Province, trillions of cubic feet, and

R_{EST} = Established initial marketable reserves at the time of application of the formula, trillions of cubic feet.

Using the potential initial marketable reserves of 100 trillion cubic feet, established initial marketable reserves of 53.2 trillion cubic feet determined in this report and the formula, 4.5 years of growth of gas reserves should be used at this time.

The Board is confident that the growth rate over the last 10 years, of 2.6 trillion cubic feet per year will continue for four and one-half years into the future so that future reserves of 11.7 trillion cubic feet can be relied upon.

APPENDIX C

ALBERTA GAS REQUIREMENTS AND PRESENT PERMIT COMMITMENTS

Alberta Requirements

(1) Views of Consolidated

The applicant stated that in its opinion the 30-year domestic gas requirements of the Province would be somewhat less than the total estimated by the Board in OGCB Report 68-A[(1)]. This opinion was primarily predicated on a review of Alberta population projections undertaken by Consolidated. Consolidated estimated that by 1998 the population of the Province would be 2,425,000 and that the average annual growth rate, initial to terminal year, would be 1.5 per cent.

Mr. Garfoot, a witness for the applicant, indicated its population forecast had been prepared by the component method of projection, based on age-specific fertility rates, age-specific mortality rates and migration. In particular, the applicant assumed age-specific fertility rates would remain constant at about the 1966 to 1967 level; the level of net migration into Alberta was assumed to be zero. The Consolidated forecast compared very closely for the year 1981 with a forecast prepared in 1968 by the Alberta Bureau of Statistics.

In estimating domestic gas requirements, Consolidated assumed that both the proportion of the provincial population served by gas and the level of per capita consumption would be slightly higher than estimated by the Board in its last analysis.

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(1) Report of an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. November 1968.

Consolidated's estimates of commercial requirements were prepared in a manner similar to its domestic projection. The total requirements for the period 1969 to 1998 inclusive for the domestic and commercial categories were estimated as 2,355 billion and 2,098 billion cubic feet respectively.

With respect to industrial requirements, the applicant adopted the Board's estimate published in OGCB Report 68-A. However, the applicant increased that forecast by 4.0 billion cubic feet in each year to allow for additional processing plant shrinkage resulting from permits authorized since preparation of OGCB Report 68-A. The Board has recognized this increase and recently revised its estimate of industrial requirements to provide for a higher forecast of 'other' industrial requirements. The applicant's forecast of population, the population to be served by natural gas and the domestic, commercial and industrial gas requirements for 1969 to 1998 inclusive are shown in Table C-1.

(2) Views of the Board

Since the Board decided in OGCB 69-D[(2)] to hold a requirements hearing in 1970, and having regard for the applicant's evidence, the Board does not believe it necessary at this time to undertake a detailed review of its previous forecasts. Rather, the Board has decided to retain its estimate of gas requirements of 15,731 billion cubic feet for the period June 1, 1969 to May 31, 1999 published in OGCB Report 69-F[(3)]. This estimate does

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(2) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October 1969.

(3) In the Matter of an Application of Trans-Canada Pipelines Limited under The Gas Resources Preservation Act, 1956. November 1969.

not include an estimated volume of 130 billion cubic feet of 'other' industrial requirements resulting from the granting of Permit No. TC 69-9 to Trans-Canada. The Board will consider the evidence of Consolidated when it undertakes a new forecast following the 1970 requirements hearing.

Table C-2 summarizes the forecast of Alberta gas requirements for the period January 1, 1969 to December 31, 1998. The adjustment to the June 1 commencement date is shown in the table below:

	Bcf
Alberta Requirements January 1, 1969 to December 31, 1998 as per Table C-2	15,538
Less Estimated Consumption January to May, 1969 inclusive	137
Plus Forecast Consumption January to May, 1999 inclusive	330
Alberta Requirements June 1, 1969 to May 1, 1999	15,731

Table C-2 also summarizes the forecast of Alberta gas requirements presented at the hearing by Consolidated and the most recent forecast prepared by the Utility Companies and available to the Board.

Permit Commitments

The present permit commitments and the maximum daily authorized withdrawal rates relate to the permits issued and listed in Table C-3. At May 31, 1969, initial permit volumes totalled some 31.7 trillion cubic feet of gas. At that date approximately 5.8 trillion cubic feet or 18.3 per cent of initial permit volumes had been removed from the Province, resulting in a remaining commitment of some 25.9 trillion cubic feet. This is equivalent to some 26.1 trillion cubic feet of 1,000 Btu per cubic foot gas.

The recent amendment to the Trans-Canada permit increased the remaining permit commitment by some 2,155 billion cubic feet to a total of about 28.3 trillion cubic feet. This is the remaining permit commitment the Board will consider in its assessment of the gas surplus to Alberta's requirements and the permit commitments.

TABLE C-1

Consolidated Natural Gas Limited Alberta
Forecast of Population and Gas Requirements
(Gas Volumes in Bcf at 1000 Btu/cu.ft.

Year	Total Population (1000)	Population Served by Gas (1000)	Domestic Requirements	Commercial Requirements	Industrial Requirements	Total Requirements
1969	1,532	1,218	57.1	48.7	160.0	265.8
1970	1,555	1,244	58.3	49.8	183.4	291.5
1971	1,578	1,273	59.6	51.1	198.4	309.1
1972	1,605	1,302	60.8	52.3	210.5	323.6
1973	1,631	1,337	62.3	53.7	224.3	340.3
1974	1,658	1,368	63.7	55.1	239.1	357.9
1975	1,685	1,402	65.2	56.5	247.1	368.8
1976	1,711	1,436	66.6	57.9	263.0	387.5
1977	1,742	1,469	68.1	59.3	273.0	400.4
1978	1,773	1,505	69.7	60.9	285.6	416.2
1979	1,803	1,542	71.2	62.4	298.3	431.9
1980	1,834	1,575	72.8	63.9	310.6	447.3
1981	1,865	1,613	74.4	65.6	323.5	463.5
1982	1,898	1,651	76.0	67.1	333.1	476.2
1983	1,931	1,693	77.7	68.9	343.3	489.9
1984	1,964	1,728	79.3	70.4	352.0	501.7
1985	1,997	1,767	80.9	72.0	360.2	513.1
1986	2,030	1,805	82.5	73.7	369.2	525.4
1987	2,063	1,846	84.2	75.4	373.7	533.3
1988	2,096	1,884	85.9	77.1	382.5	545.5
1989	2,129	1,922	87.5	78.8	389.5	555.8
1990	2,161	1,964	89.2	80.5	398.5	568.2
1991	2,194	2,003	90.9	82.3	408.8	582.0
1992	2,227	2,033	92.1	83.7	412.8	588.6
1993	2,259	2,062	93.3	85.0	426.1	604.4
1994	2,292	2,093	94.5	86.3	438.4	619.2
1995	2,324	2,124	95.8	87.7	448.4	631.9
1996	2,357	2,157	97.1	89.2	461.5	647.8
1997	2,391	2,188	98.5	90.7	474.7	663.9
1998	2,425	2,219	99.9	92.2	488.0	680.1
Total			2,355.1	2,098.2	10,077.5	14,530.8

TABLE C-2

Summary of Forecast of Alberta Gas Requirements
for Period January 1, 1969 to December 31, 1998
(Billions of Cubic Feet of 1,000 Btu Gas)

	Utility Companies 1966 (1)	Consolidated Natural Gas Ltd.	Revised Board 1966
Domestic			
1969 Annual	56.0	57.1	55.9
1998 Annual	115.5	99.9	126.5
30-year Total	2,511.6	2,355.1	2,659.6
Commercial			
1969 Annual	44.7	48.7	43.7
1998 Annual	93.0	92.2	105.7
30-year Total	2,013.2	2,098.2	2,174.7
Industrial & Contingency			
1969 Annual	166.2	160.0	171.6
1998 Annual	429.2	488.0	488.2
30-year Total	9,896.4(2)	10,077.5	10,703.2(2)
Total			
1969 Annual	266.9	265.8	271.2
1998 Annual	637.7	680.1	720.4
30-year Total	14,421.2	14,530.8	15,537.5
Equivalent Average Annual Growth Rate to Achieve Terminal Year (%)	3.0	3.3	3.4
Equivalent Average Annual Growth Rate to Achieve 30-year Total (%)	3.8	3.8	4.1

(1) Industrial and Total numbers adjusted to include Board's revised estimate of 'other' industrial consumption.

(2) Not included in these totals are 'other' industrial requirements of some 130 billion cubic feet resulting from the granting of Permit TC No. 69-9 to Trans-Canada, and some 100 billion cubic feet which the Board believes would result from the granting of a permit to Consolidated at the reduced volumes set forth in Section IV of this report. These requirements relate to trunk line fuel requirements and to fuel and shrinkage at plants which reprocess pipe line gas.

TABLE C-3

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND $60^{o}F$)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	TOTAL BCF	WITHDRAWN TO MAY 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
AS 69-5	ALBERTA AND SOUTHERN GAS CO. LTD.	1,270.0	416.0	9,422.0	1,388.6	8,033.4
	BELLOY, BERLAND RIVER, BIGORAY, BIGSTONE, BRAZEAU RIVER, CAROLINE, CARSON CREEK, CARSON CREEK NORTH, CROSSFIELD (RUNDLE A POOL), EAGLESHAM, FERRIER (VIKING A AND CARDIUM B POOLS), FOX CREEK, GOLD CREEK, HARMATTAN-ELKTON (D-3A POOL), HOMEGLEN-RIMBEY, HUNTER VALLEY, JUDY CREEK. KAYBOB, KAYBOB SOUTH (VIKING A. CADOMIN A, CADOMIN B, CADOMIN C, CADOMIN D AND TRIASSIC A POOLS), MARLBORO, MINNEHIK-BUCK LAKE, OPEN CREEK, PEMBINA (LOBSTICK GLAUCONITIC A, LOBSTICK GLAUCONITIC C, GLAUCONITIC D, LOBSTICK OSTRACOD A, LOBSTICK OSTRACOD B AND PEKISKO B POOLS, PINE CREEK, PINE NORTH-WEST, SIMONETTE, STURGEON LAKE SOUTH, SUNDRE, SWAN HILLS, SWAN HILLS SOUTH, SYLVAN LAKE, TANGENT, VIRGINIA HILLS, WASKAHIGAN, WATERTON, WESTEROSE SOUTH, WESTWARD HO, WILDCAT HILLS, WILDHORSE CREEK, WILLESDEN GREEN, WILSON CREEK, WINDFALL.					
CD 63-1	CANADIAN DELHI OIL LTD. - MEDICINE HAT	4.3	1.57	32.3	4.1	28.2

TABLE C-3 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSI AND 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT		PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	TOTAL BCF	WITHDRAWN TO MAY 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
CM 54-1 AND CM 61-2	CANADIAN-MONTANA PIPELINE COMPANY						
	ADEN, BLACK BUTTE, COMREY, KNAPPEN, MANYBERRIES,						
	PAKOWKI LAKE, PENDENT D'OREILLE, SMITH COULEE.		100.0	20.0	498.0 (1)	249.1	248.9
CP 63-1	CANADIAN PACIFIC OIL AND GAS LIMITED	- MEDICINE HAT	0.1	0.0365	0.750	0.126	0.624
BH 61-1	DELTA GAS & TRANSMISSION LTD						
BS 61-1	BAILEY SELBURN OIL AND GAS LTD						
CS 61-1	THE CALIFORNIA STANDARD COMPANY						
COG 61-1	CHARTER OIL AND GAS LTD	MEDICINE HAT	9.5	3.5	71.0	-	71.0
SEL 61-1	SELBAY EXPLORATION LTD						
JMW 61-1	J MERRIL WRIGHT, JR						
CEL 61-1	CROWFOOT EXPLORATION LTD						
CMM 61-1	IMPERIAL OIL DEVELOPMENT LIMITED						
MOG 61-1	MIC MAC OILS (1963) LTD.	MEDICINE HAT	8.3	3.0	62.0	10.2	51.8
ROC 61-1	RICHFIELD OIL CORPORATION						
ROC 65-2	ATLANTIC RICHFIELD COMPANY	- MEDICINE HAT	0.26	0.088	2.0	0.2	1.8
HB 63-1	HUDSON'S BAY OIL AND GAS COMPANY LIMITED	MEDICINE HAT	1.02	0.372	7.65	0.57	7.08
SPC 57-1	MANY ISLAND PIPE LINES LTD	- MEDICINE HAT	135.5	44.5	609.4	204.3	405.1
MO 66-1	MURPHY OIL COMPANY LTD	- RED COULEE	0.6	-	0.5	-	0.5
NSU 64-1	THE BRITISH AMERICAN OIL COMPANY LIMITED						
	ROYALITE OIL COMPANY LIMITED	- ANTELOPE AND ESTHER	11.4	4.2	40.0	10.8	29.2
	SUN OIL COMPANY						
	UNITED CANSO OIL & GAS LTD						

(1) TOTAL INITIAL MARKETABLE GAS IN THE FIELDS SHOWN.

TABLE C-3 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO MAY 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
	PEACE RIVER TRANSMISSION COMPANY LIMITED – POUCE COUPE	6.0	0.6	13.0	12.5	20.2
	PEACE RIVER TRANSMISSION COMPANY LIMITED – POUCE COUPE SOUTH	6.9	0.98	19.7		
B 68-1	PATRICK T. BUCKLEY – VANALTA NO. 4 WELL	1.0 MMCF PER MONTH	0.005	–	0.06	–
PG 64-1	TRANS-CANADA PIPE LINES LIMITED – HALLIDAY, RICHDALE AND WILDUNN CREEK	10.0	3.6	45.0	5.4	39.6
TC 68-8	TRANS-CANADA PIPE LINES LIMITED	2,715.0	860.0	19,200.0	3,233.2	15,966.8
	ALDERSON, AMISK, ARMADA, ATLEE-BUFFALO, BASHAW, BASSANO, BELLIS, BERRY, BIG BEND, BINDLOSS, BLACK DIAMOND, BLUERIDGE, BOYLE, BRAZEAU RIVER, BRUCE, BURNT TIMBER, CAROLINE (VIKING A, VIKING E, AND BASAL MANNVILLE A POOLS), CARSTAIRS, CASSILS, CASTOR, CESSFORD, CHESTERMERE, CHIGWELL, CONNORSVILLE, COUNTESS, CRAIGEND, CROSSFIELD, CROSSFIELD EAST, DRUMHELLER, EDSON, ENCHANT, EQUITY, ERSKINE, FENN WEST FERRIER, FIGURE LAKE, FLAT, GARRINGTON (MANNVILLE A AND LEDUC A POOLS), GHOST PINE, GILBY, GOODWIN, GREENCOURT, HACKETT, HAMILTON LAKE, HARMATTAN EAST, HARMATTAN-ELKTON (RUNDLE A POOL) HOMEGLEN-RIMBEY, HUGHENDEN, HUNTER VALLEY, HUSSAR, INNISFAIL, JARROW,					

TABLE C-2 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO MAY 31, 1969 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
	JUMPING POUND WEST, KILLAM, LATHOM, LECKIE, LITTLE BOW, LONE PINE CREEK, LONG COULEE, LOOKOUT BUTTE, MALMO, MARTEN HILLS, MCMULLEN, MEDICINE HAT, MEDICINE RIVER, MITSUE, NEVIS, NEWELL, NEW NORWAY, OLDS, OYEN, PELICAN, PINCHER CREEK, PREVO, PRINCESS, PROVOST, QUIRK CREEK, RAINIER, RETLAW, RICH, ROWLEY, SCANDIA, SEDALIA, SEDGEWICK, SEIU LAKE, SIBBALD, STANDARD, SUNDRE, (BASAL MANNVILLE A AND BASAL MANNVILLE B POOLS), SUNNYNOOK, SWALWELL, SYLVAN LAKE, THREE HILLS CREEK, TROCHU, TURIN, TWINING NORTH, VERGER, VULCAN, WAYNE-ROSEDALE, WESTEROSE, WESTEROSE SOUTH, WHITECOURT, WILDHORSE CREEK, WIMBORNE, WINTERING HILLS, WOOD RIVER.					
WC 52-1	WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD.					
	BRAEBURN, GORDONDALE, POUCE COUPE, POUCE COUPE SOUTH	125.0	35.0	388.0	245.3	142.7
WC 59-3	WESTCOAST TRANSMISSION COMPANY LTD					
	CROSSFIELD (CALGARY BASAL QUARTZ, CALGARY RUNDLE, AND CALGARY WABAMUN POOL, IRRICANA, AND SAVANNA CREEK)	162.2	53.1	1,081.2	336.4	744.8
WC 61-4	WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LIMITED					
	BOUNDARY LAKE SOUTH	VOLUMES NOT TO EXCEED THOSE AUTHORIZED IN PERMIT NO. WC 52-1				

TABLE C-3 (CONTINUED)

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60°F)

PERMIT NUMBER	PERMITTEE AND FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWAN TO MAY 31, 1968 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
WC 62-5	WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD.					
	WORSLEY	53.3	16.0	220.0	79.7	140.3
		4,620.38	1,467.9515	31,712.50	5,780.556	25,932.004

APPENDIX D

THE MEETING OF ALBERTA'S REQUIREMENTS FOR GAS AND THE PRESENT PERMIT COMMITMENTS, AND THE RESULTING SURPLUS

(1) Views of Consolidated

Consolidated did not present detailed evidence to show how Alberta's 30-year requirements for gas might be met but did estimate the surplus of gas in the Province employing a method somewhat more liberal than that in use by the Board at the time the application was made. The differences related to the inclusion of a portion of deferred gas in the contractable gas reserves, the extent to which the growth in gas reserves were recognized as future reserves and the matter of cushion gas for the Westcoast Southern Alberta permit. Consolidated estimated the reserves and requirements by updating those most recently published by the Board.

Consolidated submitted a detailed table, included here as Table D-5, whereby it showed that the contractable gas reserves at April 30, 1969, exceeded the contractable requirements including the quantity of gas applied for by Trans-Canada in an earlier submission, by 3.5 trillion cubic feet. Consolidated calculated that the future surplus at April 30, 1969, was 6.6 trillion cubic feet and concluded that an overall surplus of 10.1 trillion cubic feet existed after taking account of the contractable surplus of 3.5 trillion cubic feet. Consolidated excluded from deferred reserves, gas reserves in any field, pool or area that are subject to a definite contract having a firm delivery date even though deliveries from the reserves might not start for a

few years. Also, in keeping with the view of the Alberta Division of the Canadian Petroleum Association expressed in its recent application before the Board, Consolidated included as future reserves, 4.9 years of growth at the long term growth rate of 2.5 trillion cubic feet per year. Consolidated considered unnecessary and did not include in its assessment of the surplus an allowance for cushion gas in the Westcoast Southern Alberta permit.

Consolidated submitted that its surplus calculations show that the 2.3 trillion cubic feet of gas it is seeking authorization to remove from the Province is surplus to the needs of Alberta.

(2) Views of the Utility Companies

The Utility Companies disagreed with the Consolidated treatment of both deferred gas and the cushion gas provision in the Westcoast permit and concluded that had these items been treated appropriately no surplus would exist.

(3) Views of the Cities

The cities of Calgary and Edmonton expressed some doubt as to whether a surplus would truly exist had the calculation been made on the basis currently used by the Board.

(4) Views of Trans-Canada

Trans-Canada although opposing the application, did not do so on the basis that no surplus exists. It did, however, state that it opposed Consolidated's position with respect to the treatment of both deferred gas reserves and the peak day delivery protection in the Westcoast Southern Alberta permit.

(5) Views of the Board

The Meeting of Alberta's Long Term Requirements (June 1, 1969, to May 31, 1999) The 30-year gas requirements for delivery to the markets within the Province (Alberta requirements) discussed in Appendix C have been estimated at some 15.7 trillion cubic feet. The peak day requirement in the 30th year is estimated to be some 3.5 billion cubic feet. The fields now connected to and supplying Alberta's requirements and their remaining reserves as of May 31, 1969, which total some 6.4 trillion cubic feet are shown in Table D-1. Thirty times the requirements of the first year of the period (taken as the 12 months starting June, 1969) is 8.1 trillion cubic feet. The contractable requirements, defined under the Board's policy set forth in OGCB 69-D[1] as the greater of 30 times the requirements of the first year of the period under consideration or the remaining reserves in those fields connected to and supplying Alberta requirements, are therefore 8.1 trillion cubic feet.

The contractable requirements of the 30-year period have increased by 0.7 trillion cubic feet over the contractable requirements of the 30-year period considered in OGCB Report 68-A[2]. This increase is higher than would normally be expected and occurs because

(1) Report and Decision on Review of Policies and Procedures for Considering Applications under The Gas Resources Preservation Act, 1956. October, 1969.

(2) Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. November 1968.

the requirements for the first year of the period considered in OGCB Report 68-A were under-estimated with respect to shrinkage and fuel consumption at the existing plants for the reprocessing of pipe line gas.

Table D-1 shows also the Board's interpretation of the reserve-delivery ratio of each of the fields and the average reserve-delivery ratio of the group of fields supplying Alberta's requirements. The reserves are classified in the table between major reserves, oil field gas, and small reserves plus reserves supplying small utilities. The reserve-delivery ratio is the initial gas in place adjusted for surface losses divided by the initial fully developed marketable gas deliverability. The ratios have been updated to take account of changes in reserves of pools, additional deliverability data and new discoveries.

The Board believes it is reasonable to assume that the deliverability characteristics of the 1.7 trillion cubic feet (8.1 - 6.4 = 1.7) of additional reserves needed to supply the contractable requirements will be similar to those of the contractable reserves of 6.4 trillion cubic feet now connected to and supplying the Alberta requirements. On this basis, the Board estimates that of the total of some 8.1 trillion cubic feet needed to supply the contractable Alberta requirements, some 6,100 billion cubic feet will be produced during the 30-year period and the remaining unproduced portion will be capable of sustaining a peak day delivery of some 620 million cubic feet in the 30th year. Therefore, total deliveries of about 9,600 billion cubic feet (15,700 - 6,100 = 9,600) and a 30th year peak

day delivery of about 2,880 million cubic feet (3,500 - 620 = 2,880) will be required from other sources.

The actual quantities of gas necessary to provide these deliveries may be calculated using the formula method presented in Appendix E of OGCB Report 64-11[3]. With respect to the factors to be used in the formula, the Board believes that since this gas must come in part from established gas reserves not now connected to local utilities nor authorized for removal from the Province and in part from gas reserves not yet developed, the factors should reflect the delivery characteristics of both of these sources of gas.

The Board has again reviewed the average reserve-delivery ratio to take account of changes which have occurred since the issuance of OGCB Report 68-A. It finds, as is illustrated in Table D-2, that the average reserve delivery ratio of 2.0 previously used, remains applicable. The Board has also reviewed the average reservoir recovery factor of the gas in place adjusted for surface losses and finds the factor of 0.74 as used in OGCB Report 68-A to be appropriate. This particular recovery factor represents the fraction of the remaining marketable gas in place in the Province which will be recovered and is a fraction which declines as additional gas is produced.

The following is a detailed calculation of the gas reserves necessary to meet Alberta's 30-year requirements:

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(3) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. November 1964.

From now connected sources and additional sources needed to supply the contractable requirements, for delivery during the period	6,100	
From additional sources for delivery during the period	9,600	
Total Alberta Requirements for delivery		15,700
From now connected sources and additional sources needed to supply the contractable requirements, to protect the 30th year peak(1)	2,000	
From additional sources to protect the 30th year peak(2)	3,000	
Total Alberta requirements for peak day protection		5,000
Total Alberta Requirements		20,700

(1) i.e. 8,100 - 6,100 = 2,000

(2) Determined as $R_p = 1.3\ FP_n - (1 - K)\ (1.3\ FP_n + A_1 S)$

$$= 1.3\ (2.0)\ (2,880) - (1 - 0.74) \left[1.3\ (2.0)\ (2,880) + 9,600\right]$$

$$= 7,488 - 4,443 = 3,045;$$ say 3,000 billion cubic feet

<u>The Remaining Permit Commitments.</u> The Permit commitments remaining at May 31, 1969, and adjusted to include the volumes recently approved for removal by Trans-Canada are some 28.1 trillion cubic feet before adjustments for heating value and deficiencies in reserves in certain permits.

The fields named in each of the permits are shown in Table D-3. The table shows the Board's current estimate of the remaining reserves of marketable gas and the ratio of initial marketable gas in place to delivery capacity for each field.

In Table D-3 the remaining reserves of the Crossfield Field for which Alberta and Southern, Trans-Canada and Westcoast all have permits, have been apportioned among them on the basis of the Board's knowledge of their contracts. The entire remaining reserves which the Board attributes in Table A-1 to the Crossfield Rundle A Pool have been shown as named in the permit of Alberta and Southern since the Board believes it to be the only permittee with contracts for gas reserves in the pool. For a similar reason, the Cardium solution gas and the reserves in the Crossfield Basal Quartz G Pool and the Crossfield Rundle D Pool have been shown as available to Trans-Canada. The reserves attributed in Table A-1 to all other pools in the Crossfield Field, where both Trans-Canada and Westcoast have gas under contract, are apportioned between these permittees in Table D-3. Westcoast has contracted for 1.0 trillion cubic feet of the gas in these pools and has first right to all deliverability until its contract volume is produced. Trans-Canada has the remainder under commitment subject to the Westcoast preference on deliverability. The gas will be available to Trans-Canada during the term of the Westcoast permit and at least in part following termination of the Westcoast permit. A deliverability study completed by the Board but not published in this report indicates that on the basis of 1,000 Btu per cubic foot gas, some 220 billion cubic feet can be delivered to Trans-Canada during the term of the Westcoast permit while still meeting the Westcoast delivery commitments. The study shows that an additional 235 billion cubic feet will be available to Trans-Canada following termination of the Westcoast permit

but prior to the termination of the Trans-Canada permit. Trans-Canada has an additional 27 billion cubic feet of Crossfield gas reserves under contract in the previously mentioned pools where no other purchase contracts exist. Accordingly, some 482 billion cubic feet of gas from the Crossfield Field have been included in Table D-3 as reserves in permit fields available to Trans-Canada. The remaining Crossfield reserves, other than those in the Rundle A Pool which has been shown subject to the Alberta and Southern permit, have been included in the Westcoast permit.

With respect to certain of those fields recently added to the Trans-Canada permit, the Board has assessed the contract data respecting the Strachan and Ricinus Fields provided it at the hearing of the subject application and also at the earlier hearing of the Trans-Canada application. By combining the submitted evidence respecting contracts, and its own gas reserves picture for the Strachan Field, the Board has estimated that of the total marketable reserves of 1,540 billion cubic feet of 1,000 Btu per cubic foot gas, Trans-Canada has approximately 901 billion cubic feet under contract. This quantity has been included in Table D-3 as reserves in the Strachan Field available to Trans-Canada. The table also includes as available to Trans-Canada, 44 billion cubic feet of the reserves in the Ricinus Field where both Trans-Canada and Consolidated have contracts.

Division of reserves between permittees or permittees and provincial requirements have also been made for the Brazeau River, Caroline, Ferrier, Harmattan-Elkton, Homeglen-Rimbey, Hunter Valley,

Jumping Pound West, Judy Creek, Medicine Hat, Pembina, Provost, Swan Hills, Swan Hills South, Sylvan Lake, Virginia Hills, Wayne-Rosedale and Westerose South Fields as well as a number of of smaller fields. The division of reserves for these fields has been made on the basis of the Board policy spelled out in detail in OGCB 69-D.

The results of the Board's analysis with respect to the meeting of the remaining permit commitments are shown in Table D-4. Columns 1 and 2 show respectively the remaining permit commitments and the maximum daily withdrawal authorized in each of the permits. These figures were obtained from Appendix C and have been adjusted where necessary for any deficiency in reserves in the fields, pools and areas named in the permit and also have been converted to the basis of 1,000 Btu per cubic foot using the expected average heating value of the gas as it leaves the Province. This latter adjustment reflects a recent change from the Board's earlier policy where the adjustment to the heating values was on a field basis. This change reflects the situation described in detail in the Board's Informational Letter No. IL 69-8, dated May 13, 1969. The expiry date of each of the permits is shown in column 3. Columns 4 and 5 present, where applicable, the Board's current estimate of the total remaining marketable reserves and the reserve-delivery ratio (both from Table D-3) of the fields included in each permit. Column 6 shows the composite correction factor for each of the permittees' systems for which peak load protection is provided as determined from illustrative deliverability schedules.

The estimated quantity of marketable gas in place required to meet the peak day commitments in the terminal year of each permit is shown where applicable in column 7. Column 8 shows the marketable gas equivalent of column 7. These values were obtained by deducting from column 7 the marketable gas equivalent of the gas that will remain in the reservoir at abandonment. The total marketable gas required to meet the permit requirements, both deliveries and peak day, is shown in column 9. Columns 10 and 11 present the Board's estimate of the marketable gas in the fields in the permits in excess of the permit commitments before and after the expiry date of each permit.

In the case of permits where the removal of all the reserves in the permit fields has been authorized or where no allowance for maximum day protection has been made by the Board, entries in columns 5 through 8 which support the calculation of marketable reserves required to meet the terminal year peak day, have been omitted.

The remaining commitment of the Westcoast Peace River permits provides for an adjustment described more fully in OGCB Report 66-C[4], and in Permit No. WC 62-5 related to the delivery of gas from the Worsley Field and the meeting of future requirements of an iron ore processing industry in the Peace River area. The reserves credited to these permits have been adjusted having regard for these provisions, field deliverability and the withdrawals taken from the area to December 31, 1965. The provision

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(4) Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. June, 1966.

for this market in the estimated Alberta requirements is discussed in detail in Appendix C of OGCB Report 68-A.

As stated in Section IV, the Board has retained a contractable requirement for cushion gas required for the Westcoast permit. This requirement has been recalculated on the basis of the most recent deliverability and contractual information available to the Board. The detail of the contractual situation and the results of the Board studies are presented earlier in this appendix. The reserves necessary to provide for the peak day requirements of the Westcoast permit and not producible by Trans-Canada during the term of its permit have been included in the gas needed to satisfy the Westcoast permit along with the Savanna Creek and Irricana reserves. The Board concludes that some 300 billion cubic feet of the reserves provided for the Westcoast permit will not be producible during the term of the permit and in fact is cushion gas necessary to support the terminal year peak deliveries. The Board studies also indicate that only some 100 billion cubic feet of this cushion gas will be deliverable during the interim between the termination dates of either the Westcoast or the Trans-Canada permits and the end of the 30-year protection period.

Table D-4 shows that a total marketable gas reserve of 28.6 trillion cubic feet is required to meet the existing commitments which in total provide for the removal from the Province of 28.3 trillion cubic feet. Since reserves of 29.9 trillion cubic feet are available in the permit fields, a surplus of 1.3 trillion cubic feet exists in the fields named in the permits. Several

years before the end of the 30-year period, an additional 300 billion cubic feet, the amount allowed to meet the terminal year peak day deliveries for the Westcoast permit, will also become excess to the existing permit commitments.

<u>The Gas Surplus to Alberta's Requirements and the Permit Commitment.</u> The surplus calculation using the method recently adopted by the Board and discussed in detail in OGCB 69-D is illustrated in Table D-6. In preparing this table, the Board has not accepted the Consolidated position that all of the reserves in the Kaybob Beaverhill Lake A Pool should be reclassified from deferred to contractable. In keeping with the policy announced and discussed in detail in OGCB 69-D, the Board has recognized as contractable only a portion of the reserves in the pool. This portion has been determined as that part of the reserves that the Board estimates as producible during the period being considered. The first component of the total producible reserves is the production that would result if the approved sales rate of 75 million cubic feet per day is projected to the end of the 30-year protection period. The second component is the additional production that would result from the reserves under contract to Consolidated if the sales rate were increased to one million cubic feet per day for each 7.3 billion cubic feet of reserves beginning in 1980 and continuing through 1994. The production thus projected results in a contractable classification for some 1,480 billion cubic feet of a total reserve of 2,289 billion cubic feet in the Kaybob South Beaverhill Lake A Pool. The above quantities are on the basis of 1,000 Btu per cubic foot.

Table D-6 shows that the Board's estimate of contractable reserves; the reserves within economic reach (43.9 trillion cubic feet) less the deferred reserves (4.3 trillion cubic feet) totals some 39.6 trillion cubic feet. The deferred reserves are listed in Table D-7 which shows that the entire 4.3 trillion cubic feet is expected by the Board to become marketable within 30 years. The contractable requirements include 8.1 trillion cubic feet needed to supply the Alberta contractable requirements (6.4 trillion cubic feet of which are now connected to supply Alberta's requirements) and 28.6 to meet the permit commitments. The comparison of the contractable reserves and contractable requirements results in a contractable surplus of 2.9 trillion cubic feet.

The table also shows that the remaining Alberta requirements total some 12.6 trillion cubic feet. These are made up of some 9.6 trillion cubic feet which the Board believes will have to be delivered during the 30-year period and some 3.0 trillion cubic feet which the Board estimates will be necessary to provide for the 30th-year peak day.

The remaining and future reserves available to meet these Alberta requirements are shown to total some 18.5 trillion cubic feet. These are made up of 4.3 trillion cubic feet of deferred gas which the Board believes will be available within the 30-year period, some 2.2 trillion cubic feet of reserves now beyond economic reach but which the Board believes will be within economic reach within 30 years, some 0.3 trillion cubic feet allocated to protect peak day requirements in certain permits but available within 30 years and 11.7 trillion cubic feet of future gas reserves.

The detail of the deferred reserves which will become marketable within 30 years is shown in Table D-7. The Board studies indicate that of the total deferred reserves of some 4.3 trillion cubic feet, about 2.1 trillion cubic feet will be deliverable during the 30-year period and the remaining 2.2 trillion cubic feet will be available to assist in the meeting of the 30th-year peak day.

The 2.2 trillion cubic feet of reserves now beyond economic reach but expected to be available within 30 years was obtained by taking 75 per cent of the reserves now considered beyond economic reach. The Board expects that essentially all of this gas will be deliverable during the 30-year period.

The 0.3 trillion cubic feet available from the cushion gas portion of permit requirements results from the detailed delivery schedules prepared for the Crossfield Field. The schedules also show that approximately 0.1 trillion cubic feet of this cushion gas will be deliverable during the 30-year period and that some 0.2 trillion cubic feet will be available towards the 30th-year peak day requirements.

Prior to the inclusion in the future surplus calculation of all of the reserves available within 30 years from the above mentioned three categories, the Board has made one further test. Detailed studies indicate that some 4.4 trillion cubic feet of these reserves are actually deliverable within 30 years and that the remaining 2.4 trillion cubic feet will be available to meet the 30th-year peak day requirement. Since the 2.4 trillion cubic feet is less than the 3.0 trillion cubic feet shown earlier in

Table D-6 as required from other sources to meet the 30th-year peak day, the Board believes that the total of these reserves, some 6.8 trillion cubic feet, should be included in remaining reserves.

The future reserves have been determined in Appendix B as 11.7 trillion cubic feet. Table D-6 shows that the total remaining reserves exceed the total remaining requirements by 5.9 trillion cubic feet.

TABLE D-1

RESERVES AND RESERVE-DELIVERY RATIOS OF FIELDS
SUPPLYING ALBERTA'S REQUIREMENTS FOR GAS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD		MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO (1) BCF/MMCFD
MAJOR RESERVES			
BEAVERHILL LAKE - FORT SASKATCHEWAN		383	0.8
BOW ISLAND		27	0.9
CARBON		122	0.9
FAIRYDELL-BON ACCORD		77	0.7
FOREMOST		18	0.8
JUDY CREEK		31	1.0
JUMPING POUND		297	3.7
JUMPING POUND WEST		661	7.7
MEDICINE HAT		342	3.6
MORINVILLE		58	1.6
OKOTOKS		119	4.0
PADDLE RIVER		154	1.2
SARCEE		109	1.5
ST. ALBERT-BIG LAKE		50	1.7
TURNER VALLEY		197	4.6
VIKING KINSELLA		399	1.8
WAYNE-ROSEDALE		133	1.0
WESTLOCK		203	1.2
WORSLEY		150	0.4
	TOTAL	3,530	
	WEIGHTED AVERAGE		1.7
OIL FIELD GAS			
ACHESON		20	10.3
ACHESON EAST		4	6.0
BONNIE GLEN		273	27.4
FENN-BIG VALLEY		10	20.8

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

TABLE D-1 (CONTINUED)

FIELD		MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
GLEN PARK		10	28.0
JUDY CREEK		177	35.2
LEDUC-WOODBEND		29	5.0
PEMBINA		831	36.0
REDWATER		44	26.8
SAMSON		2	3.9
SIMONETTE		89	27.5
STETTLER		2	6.0
SWAN HILLS		239	40.7
SWAN HILLS SOUTH		123	42.7
VIRGINIA HILLS		34	34.8
WIZARD LAKE		108	30.9
	TOTAL	1995	
	WEIGHTED AVERAGE		25.9
SMALL RESERVES PLUS RESERVES SUPPLYING SMALL UTILITIES			
ACHESON		23	1.2
ALDERSON		16	9.1
ALEXANDER		11	0.5
ATHABASCA		6	1.5
ATHABASCA EAST		2	0.6
ATIM		2	0.3
BANTRY		35	13.2
BEAVER CROSSING		1	0.3
BITTERN LAKE		99	2.2
BONNIE GLEN		7	3.5
BONNYVILLE		1	0.1
BROOKS		3	9.5
CALAIS		21	1.0
CALLING LAKE		37	2.2
CASTOR		3	0.3
CHARLOTTE LAKE		2	0.4
COLD LAKE		2	0.4

TABLE D-1 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
CRAIG LAKE	1	0.3
DOWLING LAKE	1	0.3
DUVERNAY	1	0.6
EDWAND	3	0.1
ELK POINT	1	1.0
ELLERSLIE	1	0.1
ETHEL LAKE	2	0.4
ETZIKOM	13	1.7
EXCELSIOR	36	1.0
FLAT	10	1.5
FORT KENT	2	0.1
GLEN PARK	5	1.2
HAIRY HILL	10	0.6
HAMELIN CREEK	33	1.2
HANNA	11	2.5
HEART RIVER	2	0.1
HERCULES	30	2.3
HOLMBERG	22	1.3
KILLAM NORTH	18	0.9
KNOPCIK	12	1.0
LAC LA BICHE	7	1.0
LEAHURST	13	1.4
LEGAL	2	1.0
LINDBERGH	12	1.0
LLOYDMINSTER	2	0.5
MURIEL LAKE	5	0.4
NORMANDVILLE	39	5.0
OBERLIN	–	1.0
PROVOST	8	1.7
REDLAND	15	0.6
RYCROFT	12	1.6
SADDLE HILLS	52	5.5
SEXSMITH	4	0.7

TABLE D-1 (CONTINUED)

FIELD		MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
ST. PAUL		–	0.8
STRATHMORE		15	2.5
STROME		1	0.8
STURGEON LAKE SOUTH		2	0.5
THORHILD		11	1.0
TWEEDIE		50	0.7
WAINWRIGHT		17	1.0
WATTS		1	0.9
WHITELAW		45	1.9
WILDMERE		17	1.0
WILLINGDON		12	0.7
WINNIFRED		6	3.0
WIZARD LAKE		3	0.5
WOKING		12	0.9
	TOTAL	850	
	WEIGHTED AVERAGE		1.0
TOTAL RESERVES CONNECTED AND SUPPLYING REQUIREMENTS		6,375	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO			2.4

TABLE D-2

SUMMARY OF RESERVES AND

AVERAGE RESERVE-DELIVERY RATIO FOR ALL

RESERVES IN THE PROVINCE

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD	MARKETABLE RESERVES AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO[1] BCF/MMCFD
RESERVES NOW SUPPLYING ALBERTA'S REQUIREMENTS (SEE TABLE D-1)	6,375	2.4
FIELDS INCLUDED IN PERMIT (SEE TABLE D-3)	29,931	1.9
FIELDS APPLIED FOR BY CONSOLIDATED NATURAL GAS LIMITED[2] (SEE TABLE E-1)	1,679	1.7
REMAINING ESTABLISHED RESERVES[2]	8,775	1.9
TOTAL RECOVERABLE RESERVES IN THE PROVINCE	46,760	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO		2.0

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

(2) INCLUDES DEFERRED RESERVES AND RESERVES NOW CONSIDERED BEYOND ECONOMIC REACH.

TABLE D-3

MARKETABLE RESERVES AVAILABLE AND RESERVE-DELIVERY RATIOS OF THE FIELDS INCLUDED IN PERMITS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE DELIVERY RATIO (1) BCF/MMCFD
ALBERTA AND SOUTHERN GAS CO. LTD. (PERMIT NO. AS 69-5)		
BELLOY	79	2.8
BERLAND RIVER	297	1.2
BIGORAY	32	1.8
BIGSTONE	316	3.3
BRAZEAU RIVER	134	3.8
CAROLINE	53	1.7
CARSON CREEK	255	0.8
CARSON CREEK NORTH	175	24.2
CROSSFIELD	872	1.2
EAGLESHAM	65	4.6
FERRIER	14	7.5
FOX CREEK	126	1.8
GOLD CREEK	404	4.1
HARMATTAN-ELKTON	155	3.3
HOMEGLEN-RIMBEY	133	0.7
HUNTER VALLEY	20	3.0
JUDY CREEK, SWAN HILLS, SWAN HILLS SOUTH, AND VIRGINIA HILLS	281	37.9
KAYBOB	432	1.4
KAYBOB SOUTH	97	2.4
MARLBORO	40	5.1
MINNEHIK-BUCK LAKE	495	1.6
OPEN CREEK	36	4.7
PEMBINA	193	4.3
PINE CREEK	105	1.5
PINE NORTH-WEST	188	13.7

(1) THE INITIAL GAS IN PLACE ADJUSTED FOR SURFACE LOSSES DIVIDED BY THE INITIAL FULLY DEVELOPED MARKETABLE GAS DELIVERABILITY.

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
SIMONETTE	60	2.3
STURGEON LAKE SOUTH	72	14.6
SUNDRE	33	9.3
SYLVAN LAKE	7	2.3
TANGENT	64	3.6
WASKAHIGAN	107	4.1
WATERTON	1,953	3.1
WESTEROSE SOUTH	446	0.5
WESTWARD HO	-	-
WILDCAT HILLS	477	5.9
WILDHORSE CREEK	56	4.6
WILLESDEN GREEN	154	12.9
WILSON CREEK	52	2.2
WINDFALL	498	1.0
TOTAL	8,976	
WEIGHTED AVERAGE		1.8
CANADIAN-MONTANA PIPELINE COMPANY (PERMIT NO. CM 54-1 AND CM 61-2)		
ADEN	12	2.1
BLACK BUTTE	49	3.4
COMREY	27	2.8
KNAPPEN	17	2.0
MANYBERRIES	6	1.1
PAKOWKI LAKE	10	1.4
PENDANT D'OREILLE	124	2.0
SMITH COULEE	3	1.1
TOTAL	248	
WEIGHTED AVERAGE		2.0
TRANS-CANADA PIPE LINES LIMITED (PERMIT NO. TC 69-9) FIELDS IN PERMIT BEFORE RECENT APPLICATION		
ALDERSON	335	6.0
AMISK	9	2.9
ARMADA	9	2.2
ATLEE-BUFFALO	95	2.6
BASHAW	34	0.3

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
BASSANO	14	1.4
BELLIS	36	4.1
BERRY	8	1.7
BIG BEND	68	3.2
BINDLOSS	227	3.4
BLACK DIAMOND	19	5.0
BLUE RIDGE	29	2.2
BOYLE	14	1.0
BRAZEAU RIVER	637	2.8
BRUCE	26	1.5
BURNT TIMBER	258	10.2
CAROLINE	127	2.0
CARSTAIRS	669	1.7
CASSILS	9	5.6
CASTOR	26	12.7
CESSFORD	762	1.8
CHESTERMERE	28	6.0
CHIGWELL	33	1.3
CONNORSVILLE	55	3.6
COUNTESS	185	0.7
CRAIGEND	188	1.8
CROSSFIELD	482	2.5
CROSSFIELD EAST	709	7.1
DRUMHELLER	69	1.2
EDSON	1,951	2.0
ENCHANT	44	0.4
EQUITY	38	2.9
ERSKINE	41	1.6
FENN WEST	7	0.5
FERRIER	309	10.1
FIGURE LAKE	32	0.9
FLAT	124	1.3
GARRINGTON	8	5.6

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
GHOST PINE	169	1.9
GILBY	691	2.0
GOODWIN	17	8.2
GREENCOURT	139	1.3
HACKETT	45	1.4
HARMATTAN EAST	56	6.6
HARMATTAN ELKTON	39	0.9
HOLMGLEN-RIMBEY	399	0.7
HUGHENDEN	5	4.4
HUNTER VALLEY	30	4.4
HUSSAR	333	0.8
INNISFAIL	79	6.1
JARROW	9	1.8
JUMPING POUND WEST	69	5.9
KILLAM	15	0.5
LATHOM	4	1.7
LECKIE	1	0.7
LITTLE BOW	28	0.7
LONE PINE CREEK	302	3.5
LONG COULEE	14	0.6
LOOKOUT BUTTE	447	4.6
MALMO	49	1.0
MARTEN HILLS	804	1.7
MCMULLEN	7	1.1
MEDICINE HAT	291	5.7
MEDICINE RIVER	281	3.4
MITSUE	211	58.9
NEVIS	667	1.8
NEWELL	2	0.5
NEW NORWAY	11	1.4
OLDS	218	2.9
OYEN	32	3.2

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
PELICAN	14	6.1
PINCHER CREEK	294	12.2
PREVO	33	3.5
PRINCESS	121	2.0
PROVOST	696	1.7
QUIRK CREEK	555	5.6
RANIER	3	0.7
RETLAW	89	1.9
RICH	12	1.2
ROWLEY	73	2.7
SCANDIA	4	2.9
SEDALIA	100	12.3
SEDGEWICK	26	1.8
SEIU LAKE	25	5.5
SIBBALD	24	2.1
STANDARD	20	5.4
SUNDRE	12	3.3
SUNNYNOOK	14	1.3
SWALWELL	5	14.0
SYLVAN LAKE	448	2.5
THREE HILLS CREEK	163	4.2
TROCHU	10	3.3
TURIN	30	2.2
TWINING NORTH	48	4.4
VERGER	37	0.8
VULCAN	30	1.6
WAYNE-ROSEDALE	180	1.0
WESTEROSE	77	21.0
WESTEROSE SOUTH	552	0.5
WHITECOURT	117	1.0
WILDHORSE CREEK	55	5.5
WIMBORNE	151	1.2

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
WINTERING HILLS	69	2.5
WOOD RIVER	15	1.4
TOTAL	17,280	
WEIGHTED AVERAGE		1.8
FIELDS RECENTLY ADDED TO PERMIT NO. TC 69-9		
ALIX (SOLUTION GAS)	1	10.0
BANTRY (SOLUTION GAS)	24	11.7
BASSANO	14	1.4
BELLIS	5	0.2
BIRCH	6	2.5
CLIVE (SOLUTION GAS)	19	24.7
JENNER	41	1.4
JUMPING POUND WEST	32	5.0
KITSIM	7	2.7
LONG COULEE	2	1.1
MIKWAN	6	3.2
MOOSE	55	10.3
OBED	159	10.4
PARFLESH	9	1.7
PLAIN	13	1.3
RANFURLY	9	1.3
RICINUS	44	23.3
STRACHAN	901	3.6
WHISKEY	111	13.4
WILLESDEN GREEN	7	6.9
WINNIFRED	11	1.2
TOTAL	1,476	
WEIGHTED AVERAGE		3.9
FIELDS RECENTLY ADDED TO PERMIT NO. TC 69-9 FROM PERMIT NO. PG 64-1		
HALLIDAY	3	1.4
RICHDALE	25	1.9
WILDUNN CREEK	18	3.3

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE GAS AT MAY 31, 1969 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
TOTAL	46	
WEIGHTED AVERAGE		2.3
TOTAL (PERMIT NO. TC 69-9)	18,802	
WEIGHTED AVERAGE (PERMIT NO. TC 69-9)		1.9
<u>WESTCOAST TRANSMISSION COMPANY LIMITED</u> (PERMIT NO. WC 59-3)		
CROSSFIELD	865	2.4
IRRICANA	11	4.1
SAVANNA CREEK	171	15.1
TOTAL	1,047	
WEIGHTED AVERAGE		4.1
<u>WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD.</u> (PERMIT NO. WC 52-1 AND WC 62-5)		
BRAEBURN	59	4.2
GORDONDALE	16	1.7
POUCE COUPE	16	1.6
POUCE COUPE SOUTH	41	1.2
WORSLEY	33	0.4
TOTAL	99	
WEIGHTED AVERAGE		1.2
<u>WESTCOAST TRANSMISSION COMPANY LIMITED AND WESTCOAST TRANSMISSION COMPANY (ALBERTA) LTD.</u> (PERMIT NO. WC 61-4)		
BOUNDARY LAKE SOUTH	56	1.4
<u>OTHERS</u>		
ANTELOPE	17	0.9
ESTHER	30	0.9
MEDICINE HAT	655	2.3
RED COULEE	1	3.3
TOTAL	703	
WEIGHTED AVERAGE		2.1
TOTAL (ALL FIELDS)	29,931	
WEIGHTED AVERAGE (ALL FIELDS)		1.9

TABLE D-4

RESERVES REQUIRED TO MEET PRESENT PERMIT COMMITMENTS [1]

(ALL VOLUMES AT 1,000 BTU CUBIC FOOT)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	REMAINING PERMIT COMMITMENT (2)									EXCESS GAS IN PERMIT FIELDS	
	TOTAL BCF	MAXIMUM DAY MMCF	TERMINAL DATE OF PERMIT	RESERVES IN PERMIT FIELDS BCF	RESERVE-DELIVERY RATIO OF PERMIT FIELDS BCF/MMCFD	COMPOSITE CORRECTION FACTOR	MARKETABLE GAS IN PLACE REQUIRED TO MEET TERMINAL PEAK DAY BCF	MARKETABLE GAS REQUIRED TO MEET TERMINAL PEAK DAY BCF	TOTAL MARKETABLE GAS TO MEET PERMIT COMMITMENT BCF	BEFORE TERMINAL DATE BCF	AFTER TERMINAL DATE BCF
ALBERTA AND SOUTHERN GAS CO. LTD.	8,218	1,299	31/10/93	8,976					8,218	758	758
CANADIAN-MONTANA PIPE LINE COMPANY	248	98	15/3/86	248					248	-	-
TRANS-CANADA PIPE LINES LIMITED (3)	18,360	2,939	31/10/94	18,802					18,360	442	442
WESTCOAST TRANSMISSION COMPANY LIMITED (3) (SOUTHERN ALBERTA)	755	164	29/2/84	1,047	4.1	0.8	554	292	1,047	-	292
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)	155	196	31/12/79	155					155	-	-
OTHERS	578	166		703				23	601	102	125
TOTALS	28,314	4,862		29,931				315	28,629	1,302	1,617
ROUNDED TOTALS	28,300	4,900		29,900				300	28,600	1,300	1,600

(1) ALL VOLUMES ARE AS OF MAY 31, 1969, EXCEPT FOR THE RECENT ADDITIONS TO THE TRANS-CANADA PERMIT.

(2) ON THE BASIS OF THE HEATING VALUE OF THE GAS AS IT LEAVES THE PROVINCE.

(3) TRANS-CANADA DELIVERIES FROM CERTAIN CROSSFIELD POOLS ARE DEPENDENT ON DELIVERABILITY SURPLUS TO THAT REQUIRED BY WESTCOAST IN THE SAME POOLS.

TABLE D-5

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS
AS OF APRIL 30, 1969 AS ESTIMATED BY CONSOLIDATED

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1,000 BTU PER CUBIC FOOT)

<u>CONTRACTABLE RESERVES</u>			
NOW CONSIDERED WITHIN ECONOMIC REACH	44.3		
LESS: DEFERRED	4.1		
TOTAL CONTRACTABLE RESERVES		40.2	
<u>CONTRACTABLE REQUIREMENTS</u>			
CONTRACTABLE ALBERTA REQUIREMENTS	8.0		
CONTRACTABLE PERMIT REQUIREMENTS	28.7		
TOTAL CONTRACTABLE REQUIREMENTS		36.7	
<u>CONTRACTABLE SURPLUS</u>			3.5
<u>REMAINING REQUIREMENTS</u>			
TOTAL RESERVES NEEDED TO MEET ALBERTA REQUIREMENTS	19.5		
LESS: CONTRACTABLE ALBERTA REQUIREMENTS	8.0		
TOTAL REMAINING REQUIREMENTS		11.5	
<u>REMAINING AND FUTURE RESERVES</u>			
FROM DEFERRED GAS AVAILABLE WITHIN THE 30-YEAR PERIOD	3.6		
FROM RESERVES WHICH WILL BECOME WITHIN ECONOMIC REACH DURING THE 30-YEAR PERIOD	2.3		
FROM APPRECIATION OF ESTABLISHED RESERVES AND FUTURE DISCOVERIES	12.2		
		18.1	
FUTURE SURPLUS			6.6
TOTAL SURPLUS			10.1

TABLE D-6

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

AS OF MAY 31, 1969 (1)

AS ESTIMATED BY THE BOARD

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1000 BTU PER CUBIC FOOT)

CONTRACTABLE RESERVES					
Now Considered Within Economic Reach			43.9		
Less: Deferred			4.3		
Total Contractable Reserves				39.6	
CONTRACTABLE REQUIREMENTS					
Contractable Alberta Requirements			8.1		
Permit Requirements:					
To meet commitments		28.3			
To meet terminal year peak day		0.3			
Total Contractable requirements				36.7	
CONTRACTABLE SURPLUS					2.9
REMAINING REQUIREMENTS					
Total Alberta Requirements For Delivery	15.7				
Less: Deliveries From Contractable Reserves	6.1				
Deliveries Required From Other Sources		9.6			
Total Alberta Requirements for Thirtieth Year Peak Day	5.0				
Less: Available From Contractable Reserves	2.0				
Required from Other Sources To Meet Thirtieth Year Peak Day		3.0			
Total Remaining Requirements			12.6		
REMAINING AND FUTURE RESERVES					
From Deferred Gas Available Within 30 Years		4.3			
From Reserves Now Considered Beyond Economic Reach		2.2			
From Reserves Providing For Terminal years peak day in permits		0.3			
From Gas Not Yet Established		11.7			
Total Remaining and Future Reserves			18.5		
FUTURE SURPLUS					5.9

(1) Reflects recent changes to Trans-Canada permit.

TABLE D-7

DEFERRED RESERVES
(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

POOL MARKETABLE WITHIN 30 YEARS	MARKETABLE RESERVES AT MAY 31, 1969 BCF
BANTRY MANNVILLE A	22
BONNIE GLEN D-3A	378
CLIVE D-2 & D-3	44
GOLDEN SPIKE D-3A	248
HARMATTAN EAST RUNDLE	949
HARMATTAN-ELKTON RUNDLE C	1,062
JOARCAM VIKING	52
KAYBOB CADOMIN B	64
KAYBOB SOUTH BEAVERHILL LAKE A	809
LEDUC-WOODBEND BLAIRMORE	51
LEDUC-WOODBEND D-2A	47
LEDUC-WOODBEND D-3A	381
SWALWELL PEKISKO	39
SYLVAN LAKE JURASSIC A	30
WESTEROSE D-3	102
OTHER SMALL AND CONFIDENTIAL RESERVES	47
TOTAL DEFERRED RESERVES	4,325

APPENDIX E

THE APPLICATION FOR AUTHORIZATION FOR THE REMOVAL OF GAS AND THE EFFECT THE AUTHORIZATION WOULD HAVE ON SURPLUS

Consolidated applied for authorization to remove from the Province 2,300 billion cubic feet of gas at a maximum daily rate of 360 million cubic feet. The gas would come from the Strachan, Ricinus and Kaybob South Fields. The volume applied for would amount to a total of 2,516 billion cubic feet and the maximum day would be 394 million cubic feet after adjustment to the basis of 1,000 Btu per cubic foot.

All volumes subsequently referred to in this appendix respecting the Consolidated application are on the basis of 1,000 Btu per cubic foot.

Table E-1 shows the fields from which Consolidated wishes to take gas for removal from the Province as well as the Board's current estimate of the remaining reserves of marketable gas available to Consolidated and the reserve-delivery ratio for each of the fields.

The Board has assessed the contract data respecting the Strachan and Ricinus Fields presented at the hearing of the subject application and also at the earlier hearing of an application by Trans-Canada to remove gas from the Province. Having regard to the submitted evidence respecting contracts and its own reserve estimate for the Strachan Field, the Board has estimated that of the total marketable reserves of 1,540 billion cubic feet, Consolidated has approximately 639 billion cubic feet under contract.

This quantity has been included in Table E-1 as reserves in the Strachan Field available to Consolidated. On a similar basis, the table also includes 44 billion cubic feet of the reserves in the Ricinus Field where both Consolidated and Trans-Canada have contracts.

With respect to the Kaybob South Beaverhill Lake A Pool, the Board has estimated, as is described in detail in Appendix D, that 1,480 billion cubic feet of the reserves are contractable. The Board has assessed the contract data available to it and has concluded that 996 billion cubic feet of this gas should be considered as available to Consolidated. The Board has thus included in Table E-1, 996 billion cubic feet from the Kaybob South Beaverhill Lake A Pool.

The Board has considered the deliverability of gas from the above mentioned three fields and although it recognizes that the reserves will not be deliverable at a constant rate over the period of the permit applied for, the Board believes that the reserves shown in Table E-1 will be deliverable during the proposed term. Accordingly, the Board is prepared to consider the Consolidated application in a modified form, involving a total of 1,679 billion cubic feet of 1,000 Btu per cubic foot gas over the term of the permit and a maximum daily rate of 263 million cubic feet. These volumes are referred to below as the reduced volumes.

The results of the Board's analysis with respect to the meeting of permit commitments and the application of Consolidated in the reduced volumes are presented in Table E-2 which is similar

in form to the previously discussed Table D-4. In fact the only changes have been to add an entry for Consolidated reflecting the reduced volumes and the reserves available to Consolidated in the fields from which the applicant proposes to remove gas.

Table E-2 shows that with the inclusion of the reduced volumes for Consolidated, the remaining permit commitments would total some 30.0 trillion cubic feet and the reserves required to meet these commitments would total some 30.3 trillion cubic feet.

Table E-3 presents the calculation of the amount of gas that would be surplus to Alberta's requirements and the permit commitments if the application of Consolidated in the reduced volumes is granted. Most of the figures used in the preparation of the table have been taken directly from Table D-6. On the basis of the Board's estimates, there would remain a contractable surplus of 1.2 trillion cubic feet if Consolidated were authorized to remove the reduced volumes from the Province. Table E-3 also shows that the remaining and future reserves would exceed the remaining requirements by some 5.9 trillion cubic feet.

Increased Alberta requirements of some 130 billion cubic feet over the 30-year period will likely result from the recent granting of Trans-Canada's application due to additional extraction of natural gas liquids at the Empress gas reprocessing plants and increased fuel requirements of The Alberta Gas Trunk Line Company Limited (Trunk Line). A further additional Alberta requirement would occur in the form of fuel requirements of Trunk Line and, if the gas is reprocessed at the Empress reprocessing plants,

in the form of plant fuel and shrinkage, if Consolidated's application is granted for the reduced volumes. The Board believes these additional Alberta requirements from granting the Consolidated application might total some 110 billion cubic feet. However, even after considering the total anticipated additional Alberta requirements of 240 billion cubic feet, a substantial surplus would remain.

TABLE E-1

MARKETABLE RESERVES AND RESERVE-DELIVERY RATIO OF FIELDS
APPLIED FOR BY AND AVAILABLE TO CONSOLIDATED

(All Volumes at 1000 Btu Per Cubic Foot)

FIELD		MARKETABLE GAS AT MAY 31, 1969 Bcf	RESERVE-DELIVERY RATIO (1) Bcf/MMcfd
Kaybob South		996	1.3
Ricinus		44	23.3
Strachan		639	3.6
	TOTAL	1,679	
	WEIGHTED AVERAGE		1.7

(1) The initial gas in place adjusted for surface losses divided by the initial fully developed marketable gas deliverability.

TABLE E-2

RESERVES REQUIRED TO MEET PRESENT PERMIT COMMITMENTS
AND THE ADJUSTED CONSOLIDATED APPLICATION (1)

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	REMAINING PERMIT COMMITMENT (2)									EXCESS GAS IN PERMIT FIELDS	
PERMITTEE	TOTAL BCF	MAXIMUM DAY MMCF	TERMINAL DATE OF PERMIT	RESERVES IN PERMIT FIELDS BCF	RESERVE-DELIVERY RATIO OF PERMIT FIELDS BCF/MMCFD	COMPOSITE CORRECTION FACTOR	MARKETABLE GAS IN PLACE REQUIRED TO MEET TERMINAL PEAK DAY BCF	MARKETABLE GAS REQUIRED TO MEET TERMINAL PEAK DAY BCF	TOTAL MARKETABLE GAS TO MEET PERMIT COMMITMENT BCF	BEFORE TERMINAL DATE BCF	AFTER TERMINAL DATE BCF
ALBERTA AND SOUTHERN GAS CO. LTD.	8,218	1,299	31/10/93	8,976					8,218	758	758
CANADIAN-MONTANA PIPE LINE COMPANY	248	98	15/3/86	248					248	-	-
CONSOLIDATED NATURAL GAS LIMITED	1,679	263	31/12/95	1,679					1,679	-	-
TRANS-CANADA PIPE LINES LIMITED(3)	18,360	2,939	31/10/94	18,802					18,360	442	442
WESTCOAST TRANSMISSION COMPANY LIMITED (SOUTHERN ALBERTA)(3)	755	164	29/2/84	1,047	4.1	0.8	554	292	1,047	-	292
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)	155	196	31/12/79	155					155	-	-
OTHERS	578	166		703				23	601	102	125
TOTALS	29,993	5,125		31,610				315	30,308	1,302	1,617
ROUNDED TOTALS	30,000	5,100		31,600				300	30,300	1,300	1,600

(1) ALL FIGURES ARE AS OF MAY 31, 1969, EXCEPT FOR THE RECENT ADJUSTMENTS TO THE TRANS-CANADA PERMIT.

(2) ON THE BASIS OF THE HEATING VALUE OF THE GAS AS IT LEAVES THE PROVINCE.

(3) TRANS-CANADA DELIVERIES FROM CERTAIN CROSSFIELD POOLS ARE DEPENDENT ON DELIVERABILITY SURPLUS TO THAT REQUIRED BY WESTCOAST IN THE SAME POOLS.

TABLE E-3

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS AND THE ADJUSTED CONSOLIDATED APPLICATION AS OF MAY 31, 1969 (1)
AS ESTIMATED BY THE BOARD

(All Volumes in Trillions of Cubic Feet at 1000 Btu Per Cubic Foot)

CONTRACTABLE RESERVES					
Now considered within economic reach			43.9		
Less: Deferred			4.3		
Total Contractable Reserves				39.6	
CONTRACTABLE REQUIREMENTS					
Contractable Alberta requirements			8.1		
Permit requirements – To meet remaining commitments		30.0			
– To meet terminal year peak day		0.3			
Total Contractable Requirements				38.4	
CONTRACTABLE SURPLUS					1.2
REMAINING REQUIREMENTS					
Total Alberta requirements for delivery	15.7				
Less: Deliveries from contractable reserves	6.1				
Deliveries required from other sources		9.6			
Total Alberta requirements for thirtieth year peak day	5.0				
Less: Available from contractable reserves	2.0				
Required from other sources to meet thirtieth year peak day		3.0			
Total Remaining Requirements			12.6		
REMAINING AND FUTURE RESERVES					
From deferred gas available within 30 years		4.3			
From reserves now considered beyond economic reach		2.2			
From reserves providing for terminal years peak day in permits		0.3			
From gas not yet established		11.7			
Total Remaining and Future Reserves			18.5		
FUTURE SURPLUS					5.9

(1) Reflects recent changes to Trans-Canada permit.

APPENDIX F

FORM OF PERMIT

IN THE MATTER of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956; and

IN THE MATTER of a Permit to Consolidated Natural Gas Limited authorizing the removal of gas from the Province

PERMIT NO. CNG 69-1

WHEREAS Consolidated Natural Gas Limited (hereinafter called "the Permittee") has applied to the Oil and Gas Conservation Board for a permit pursuant to The Gas Resources Preservation Act, 1956, authorizing the removal from the Province of gas produced from certain fields, pools and areas; and

WHEREAS the Board upon inquiry into and hearing of the application has found that the Permittee is a person who appears to have made arrangements to purchase gas within the Province and who proposes to remove such gas from the Province and that the provisions of The Gas Resources Preservation Act, 1956, affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of this permit for the removal of gas from the Province is in the public interest having regard to the present and future needs of persons within the Province and to the established reserves and the trends in growth and discovery of reserves of gas in the Province; and

WHEREAS the Lieutenant Governor in Council has given his approval by an Order in Council, number O.C. , and dated

THEREFORE, the Oil and Gas Conservation Board, pursuant to the provisions of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta 1956, hereby grants a permit to Consolidated Natural Gas Limited, and hereby authorizes the removal of gas from the Province, subject to the regulations and orders made pursuant to the provisions of the said Act and to the terms and conditions prescribed in this Permit as follows:

1. Subject to the confirmity by the Permittee with the terms and conditions hereof, this Permit shall be operative for a term commencing on January 1, 1971 and ending on December 31, 1995.

2. The quantity of gas that may be removed from the Province pursuant to this Permit shall not exceed

   (a) during the term of the Permit 1,535,000,000,000 cubic feet, nor

   (b) during any consecutive 24-hour period or any consecutive 12-month period ending December 31, rates limited by field productivity and good engineering practice, but in a 24-hour period such rates shall not exceed 240,000,000 cubic feet and in a 12-month period such rates shall not exceed 80,000,000,000 cubic feet.

3. The quantity of gas that may be removed from the Province in accordance with clause 2, subclause (b), during any 12-month period ending December 31, may be augmented by any part of the quantity by which gas removed from the Province under this Permit, in the last preceding four-year period ending December 31, shall have been less than the sum of the annual volumes stipulated in clause 2 to be so removed in the four-year period and which has not, in the meantime, been removed from the Province as an augmentation authorized by this clause, but nothing herein authorizes the removal of gas from the Province in any consecutive 24-hour period or during the term of the Permit in excess of the volumes stipulated for such periods in clause 2.

4. Notwithstanding the provisions of clause 2, subclause (b), the Permittee, for the purpose only of alleviating temporary operating problems caused by pipe line or equipment failure, may remove in any consecutive 24-hour period 110 per cent of the volume of gas authorized by said subclause (b).

5. The Permittee, subject to clause 8, may remove or cause to be removed from the Province under the authority of this Permit, only gas produced from the following pools, fields and areas:

Kaybob South Beaverhill Lake A Pool

Ricinus Field

Strachan Field

6. The Permittee shall satisfy the Board prior to July 1, 1970, that construction of its proposed project and any required transportation facilities will commence not later than January 1,

1971, unless upon application by the Permittee later dates are stipulated by the Board.

7. The effective commencement of the removal of gas from the Province pursuant to this Permit shall be on or before July 1, 1971, unless upon application by the Permittee a later date is stipulated by the Board.

8. Gas acquired in Alberta by the Permitee, in exchange for equal volumes of gas, adjusted for any difference in higher heating value, produced from pools, fields or areas named in clause 5, may be removed from the Province under the authority of this Permit.

9. The Permittee shall remove or cause to be removed pursuant to this Permit only such gas as is delivered to it through facilities of The Alberta Gas Trunk Line Company Limited at the interconnection of their pipe lines in the vicinity of Section 11, Township 20, Range 1, West of the 4th Meridian.

10. (1) All gas removed from the Province pursuant to this Permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located at the point at which gas is delivered in accordance with clause 9 by the Alberta Gas Trunk Line Company Limited to the Permittee.

(2) The specific gravity and higher heating value of all gas received by the Permittee through the facilities of The Alberta Gas Trunk Line Company Limited shall be measured by or on behalf of the Permittee at the point at which gas is delivered by The Alberta Gas Trunk Line Company Limited to the Permittee.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

11. Subject to section 14 of the said Act, all quantities of gas for the purpose of this Permit shall be referred to a 14.65 pounds per square inch absolute pressure base and a 60 degree Fahrenheit temperature base.

12. Notwithstanding any provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this Permit.

13. The Permittee will supply gas from the pipe line of The Alberta Gas Trunk Line Company Limited at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas for such a community or consumer, that is willing to take delivery of gas at a point on the pipe line, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

14. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 13, and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

15. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, competent regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

MADE at the City of Calgary, in the Province of Alberta, this day of , A.D. 19 .

OIL AND GAS CONSERVATION BOARD

G. W. Govier

Chairman